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ELECTRIC POWER WHEELING AND DEALING:

Technological Considerations for Increasing Competition

VOLUME II -- CONTRACTOR DOCUMENTS

Part C

1. Competition and The Role of The Capital Markets in Restructuring The Electric Power Industry
2. The Siting of EHV Electric Transmission Lines
3. Environmental Effects of Increased Competition in the Electric Power Industry
4. Economic and Planning Implications of the FERC Notice of Proposed Rulemakings on Independent Power Producers: A Review of Documentation

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COMPETITION AND THE ROLE OF THE CAPITAL MARKETS IN RESTRUCTURING THE ELECTRIC POWER INDUSTRY

JANUARY 1988

Prepared for the Office of Technology Assessment

by

Scott Fenn

Investor Responsibility Research Center

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CONTENTS

Introduction 1

Chapter I - Capital Investment in the Electric Power Industry 2

  Capital spending in the electric power sector 2
  External capital needs 3
  Other recent trends in electric power financing 8

Chapter II - Financial Restructuring in the Electric Power Industry... 14

  Increased competition: the dominant force behind restructuring .. 14
  Other forces promoting utility restructuring 21
  Types of utility restructuring activity 26

Chapter III - Investment Community Views on Utility Restructuring..... 46

Appendix A - List of persons interviewed 55

Appendix B - A glossary of investment terms 56

Footnotes 57

Introduction

The purpose of this paper is to provide the Office of Technology Assessment with an overview of some of the investment issues affecting the future of the electric power industry in support of OTA's ongoing study on competition in the industry. The paper will focus on how proposed changes in the regulation and structural organization of the industry might influence the perceptions of institutional investors and their willingness to provide capital to the industry. The paper is organized into three chapters: Chapter I provides a description of current investment issues and financial trends in the industry. Chapter II discusses the emergence of financial restructuring activity as a major factor in the industry. Chapter III presents the views of the investment community regarding regulatory and financial restructuring, the appropriate government role in regulatory reform and how proposed regulatory changes might affect the willingness of investors to provide capital to the industry.

The materials presented in this paper are from a variety of sources, including personal and telephone interviews with representatives of the investment community, relevant reports and articles that have appeared in the daily and trade press, materials presented at conferences, and published research by the author, especially the IRRC reports Mergers and Financial Restructuring in the Electric Power Industry and Institutional Investment in Renewable Energy Technologies.[1] A list of persons interviewed specifically for this report is attached in Appendix A. Acknowledgements of other persons whose views or comments are reflected in this report are found in the footnotes and in the two reports mentioned above.

Chapter I: Capital Investment in the Electric Power Industry

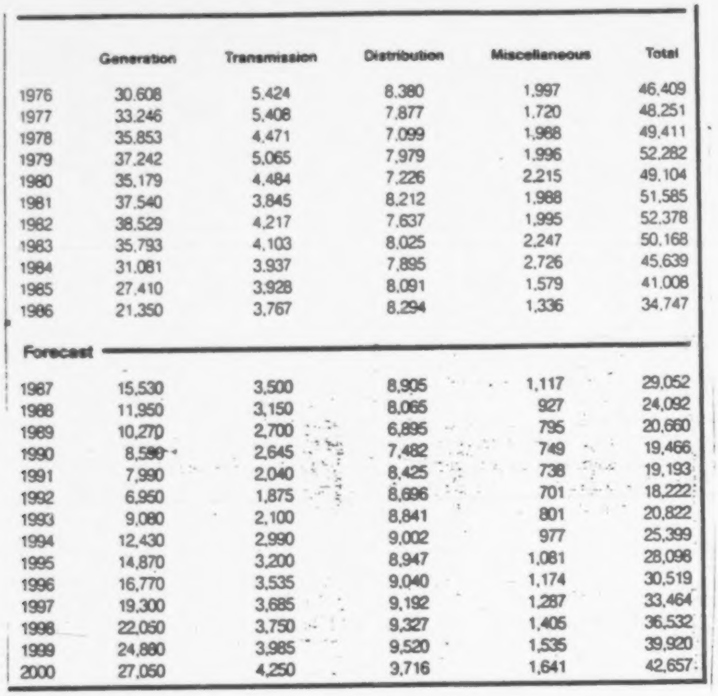
The electric power sector is one the nation's most capital intensive industries, and financing the generation, transmission and distribution assets of the industry has historically been a major factor in U.S. capital markets. As of 1980, investor-owned electric utilities had invested an average of $3.07 in plant and equipment to support each $1 in annual revenue from electricity sale. In contrast, General Motors had a fixed asset investment of 16 cents per dollar of sales revenue in 1980 and Exxon had fixed asset investments of 31 cents per dollar of sales revenue. [2] Capital spending by the electric power industry (in nominal dollars) increased from $3 billion in 1948 to more than $20 billion in 1974 to a peak of about $40 billion in 1982. Much of this expansion was financed externally through the debt and equity markets.

In recent years, capital spending in the electric power industry has begun to decline substantially, although some industry forecasts expect such spending to begin to climb sharply again by the mid-1990s as the industry enters its next building cycle. [3] Meanwhile, a variety of new trends have emerged in the ways the remainder of the industry's capital needs are financed. This chapter will examine how much capital is provided to the electric power sector, in what form, by whom and under what assumptions.

Capital spending in the electric power sector: Recent trends in capital spending by the electric utility sector--as well as one forecast of future capital needs--are shown in Table 1. As can be readily seen, capital spending in the electric power sector is falling rapidly (in real terms), principally as a result of a dramatic falloff in spending by utilities for new generating

Table 1

Total Capital Expenditures in the Electric Utility Industry
(in 1987 dollars)



	Generation	Transmission	Distribution	Miscellaneous	Total
1976	30.608	5.424	8.380	1,997	46.409
1977	33.246	5.408	7,877	1,720	48.251
1978	35.853	4.471	7.099	1,988	49.411
1979	37.242	5,065	7,979	1,996	52,282
1980	35.179	4.484	7,226	2,215	49.104
1981	37.540	3,845	8,212	1,988	51,585
1982	38.529	4,217	7,637	1,995	52,378
1983	35,793	4,103	8,025	2,247	50,168
1984	31.081	3.937	7,895	2,726	45,639
1985	27.410	3,928	8,091	1,579	41,008
1986	21,350	3,767	8,294	1,336	34,747
Forecast					
1987	15,530	3,500	8,905	1,117	29,052
1988	11,950	3,150	8,065	927	24,092
1989	10,270	2,700	6,895	795	20,660
1990	8,590	2,645	7,482	749	19,466
1991	7,990	2,040	8,425	738	19,193
1992	6,950	1,875	8,696	701	18,222
1993	9,080	2,100	8,841	801	20,822
1994	12,430	2,990	9,002	977	25,399
1995	14,870	3,200	8,947	1,081	28,098
1996	16,770	3,535	9,040	1,174	30,519
1997	19,300	3,685	9,192	1,287	33,464
1998	22,050	3,750	9,327	1,405	36,532
1999	24,880	3,985	9,520	1,535	39,920
2000	27,050	4,250	3,716	1,641	42,657

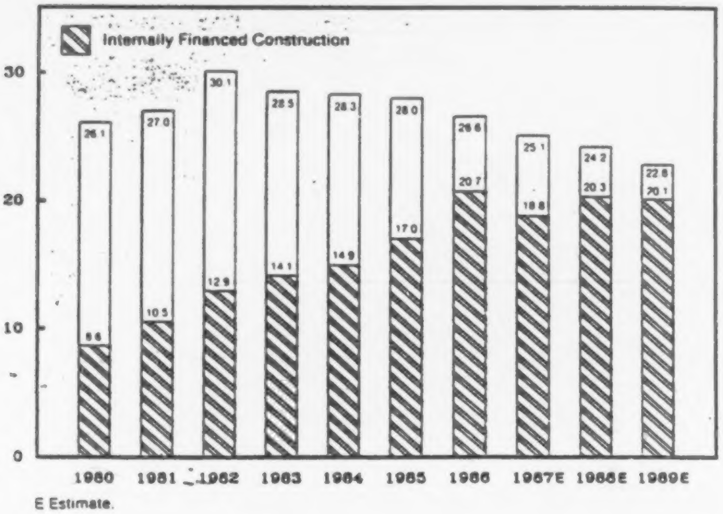
Source: Electrical World, Annual Industry Forecast, September 1987

capacity. Total capital spending in the electric utility industry has already fallen about by about one-third in real terms since it peaked in 1982, and is expected to decline considerably further before it begins to rise again in the early 1990s.

External capital needs: In the short term, the decline in overall capital spending in the industry is particularly significant because it is occurring at a time when the power industry's internal cash generation capability is climbing--meaning that less and less of the industry's capital spending needs

Figure 1

Electric Utility Construction Expenditures, 1980-89E
(Billions of Dollars)



Source: Salomon Brothers Stock Research, "Quarterly Review of Electric Utility Quality Measurements," Oct. 12, 1987.

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to be financed externally. As shown in Figure 1, Salomon Brothers Inc. predicts that the utility industry will finance 84 percent of its construction expenditures from internal funds in 1988, and 88 percent in 1989--up from only about 33 percent in 1980. In addition, Salomon Brothers estimates that by 1989, 60 percent of the electric utilities it follows will be generating all of the capital they need for construction from internal funds.

These overall figures suggest that capital availability--at least in terms of the total amounts of funds needed in the electric utility sector--is not a major problem in the electric utility sector in the near term _from an industry-wide perspective_. (This point is discussed further in Chapter III.) Rather, the capital availability problems in the industry appear to relate to certain subgroups of the industry and to perceptions of potential future problems:

- Financially weak utilities--Some utilities, such as Public Service Co. of New Hampshire and Long Island Lighting Co., are in such poor financial shape that they no longer have access to the capital markets to complete ongoing construction projects. Other utilities that have major construction projects--especially nuclear plants--underway are being forced to pay a premium for capital because of investors' perceptions that there are considerable risks associated with these projects.

- Weak non-utility developers--Many of the new non-utility power developers (both QFs and IPPs) entering the industry do not have much cash generation and also do not have the track record or the balance sheet needed to gain access to private capital markets. Those that do have to pay a risk premium because they operate in the riskiest portion of the electric power field--generation--and do not have stable earnings from a regulated monopoly franchise to offset these risks.

- Expectations of future capital needs--Some utilities, non-utility power producers and public policymakers question whether sufficient capital will be available to the electric power industry to meet expected future electricity demand growth, particularly starting in the mid-1990s.

While the existing capital needs of electric utilities are being met largely through internally generated funds, the potential for future capital availability problems suggests that the means by which the industry meets its needs for external capital remains important. Historically, the external capital needs of the electric power sector have been met with three types of long-term financing:

Common stock--the equity in the company issued to individual and institutional shareholders.

Preferred stock--typically fixed rate securities that pay dividends whose rights are superior to those of common stockholders but junior to those of debtholders.

Long-term debt--typically in the form of 10 to 30 year fixed rate mortgage bonds sold to individuals and institutions.

As shown in Table 2, the percentage of these types of capital that, along with short-term borrowings, comprise the electric utility industry's capitalization has remained relatively steady over the past 20 years, although there has been a noticeable increase in the common equity component in recent years as a consequence of the industry's improved internal cash generation.

Table 2

Capitalization Ratios of Electric Utility Industry (1965-1987)

Capitalization %	1965	1970	1975	1980	1985	(6/30) 1987
Common Equity	38.3	34.1	34.3	36.5	40.5	41.3
Preferred and Preference Stock	9.3	9.5	12.1	11.7	9.8	8.3
Long-term Debt	50.6	53.0	50.8	48.6	48.4	48.1
Short-term Debt	1.8	3.4	2.9	3.2	1.4	2.3

Sources: Leonard Hyman, America's Electric Utilities: Past, Present and Future (Public Utilities Reports, Arlington, Va., 1983); and Salomon Brothers Stock Research, "Quarterly Review," Oct. 12, 1987.

More detailed information on the types of financing and the purpose of these financings is shown below in Table 3. As can be seen, total financings by the investor-owned utilities during the first nine months of 1987 amounted to $16.8 billion, with $10.4 billion of this representing new cash raised and the remainder being refinancings.

Table 3

Securities Offerings by Investor-owned Electric Utilities
(Thousands of Dollars)

	Jan 1-Sept 30, 1987		Jan 1-Sept 30, 1986	
	Total	**Electric**	**Total**	**Electric**
Long-term debt	14,099,292	10,945,687	26,593,650	16,051,150
Preferred stock	2,389,125	1,958,000	1,183,000	1,183,000
Common stock	342,890	245,750	762,695	531,945
Total financing	**16,831,307**	**13,149,437**	**28,539,345**	**17,766,095**
Segregation of financing by type of sale				
Public				
Long-term debt	11,920,821	10,111,416	25,729,650	15,609,650
Preferred stock	2,329,125	1,958,000	1,183,000	1,183,000
Common stock	342,890	245,750	762,695	531,945
Total public	14,592,836	12,315,166	27,675,345	17,324,595
Private				
Long-term debt	2,178,471	834,271	864,000	441,500
Preferred stock	60,000			
Total private	2,238,471	834,271	864,000	441,500
Total financing	**16,831,307**	**13,149,437**	**28,539,345**	**17,766,095**
Segregation of financing by purpose of sale				
New money				
Long-term debt	8,615,978	6,092,032	10,289,838	7,429,838
Preferred stock	1,481,125	1,205,000	835,000	835,000
Common stock	328,890	245,750	728,945	498,195
Total new money	10,425,993	7,542,782	11,853,783	8,763,033
Refunding				
Long-term debt	5,483,314	4,853,655	16,303,812	8,621,312
Preferred stock	908,000	753,000	348,000	348,000
Common stock	14,000		33,750	33,750
Total refunding	6,405,314	5,606,655	16,685,562	9,003,062
Total financing	**16,831,307**	**13,149,437**	**28,539,345**	**17,766,095**
Segregation of financing by method of sale				
Competitive				
Long-term debt	3,333,500	3,033,500	7,203,000	4,413,000
Preferred stock	510,000	510,000	265,000	265,000
Common stock	36,625	36,625	216,964	165,245
Total competitive	3,880,125	3,580,125	7,684,964	4,843,245
Negotiated				
Long-term debt	8,587,321	7,077,916	18,526,650	11,196,650
Preferred stock	1,819,125	1,448,000	918,000	918,000
Common stock	306,265	209,125	545,731	366,700
Total negotiated	10,712,711	8,735,041	19,990,381	12,481,350
Private sales	2,238,471	834,271	864,000	441,500
Total financing	**16,831,307**	**13,149,437**	**28,539,345**	**17,768,095**

Source: Ebasco Business Consulting as reprinted in Electrical World, November 1987.

Other recent trends in electric power industry financing: In recent years, a number of new trends have begun to emerge in the financing of electric power facilities. Among the most significant of these trends may be the entry of non-utility entities into the power generation market, the emergence of innovative financing techniques as a major source of funding for new electric generating facilities, and the growing level of ownership of electric utility common equity by institutional investors.

New entrants into power generation sector--One of the most important new trends in the financing of the electric power industry is the fact that regulated utilities are no longer the only entities in need of capital. In the wake of the Public Utility Regulatory Policies Act of 1978, a whole new industry of non-utility entities has entered the generation side of the business. After an initial lag time of several years, growth of this non-utility side of the electric power industry has been quite rapid, as has been documented by a number of recent studies.[4]

The emergence of these new players has been important from a financing standpoint for several reasons. First, many of the companies that entered this field were start-up ventures, with financing needs that were very different from the traditional asset-based financing used by regulated utilities. As a consequence, these new companies have tended to utilize various types of innovative financing techniques to raise capital. Some of these financing methods--such as the use of leveraged project financing--have proven so successful that they are now being imitated by the rest of the industry--including some regulated utilities. Second, as these non-utility companies have matured, they have begun to undertake sizable projects, such that the overall capital needs of these non-utility entities are a growing portion of the total financing being done in the power sector.

Both of these points are illustrated in some recent data gathered by the National Association of Energy Service Companies (NAESCo). Since 1986, NAESCo has been monitoring "tombstone" advertisements run in the Wall Street Journal related to non-utility financings of power generation facilities. While NAESCo's figures for these financings should not be considered a definitive representation of the size of this market, they do tend to indicate that non-utility financings are dominated by project financings and that the overall level of these financings is now a significant portion--perhaps approaching 20 percent--of the total market for external capital in the electric power industry.[5] The relative dearth of new construction by utilities in recent years is, of course, a contributing factor in this rising percentage of non-utility financings.

Table 4

NON-UTILITY ELECTRIC POWER FINANCINGS ADVERTISED IN WALL STREET JOURNAL

	1986	1987 (9 mo.)
Total $ Value	$2,688 million	$4,426 million
# Transactions	51	67
Project Financings		
Cogeneration	$971.4 million	$2,453.3 million
Resource Recovery	517.6	773.3
Small hydro	290.6	231.5
Wood/peat-fueled	252.0	134.4
Geothermal	145.5	110.0
Wind	68.7	0
Total	$2,245.8	$3,702.5
Conventional Financings		
Total	$442.0	$723.6

Source: National Association of Energy Service Companies, various press releases

Growing use of innovative financing--As mentioned in the previous section, one of the more important effects from the influx of non-utility companies into the power industry has been the use of innovative financing methods. Basically, these companies have had to rely on non-conventional financing techniques in order to attract capital. This has been done in two ways. First, many companies have utilized project financing--where the viability of the financing depends on the project itself and the contractual arrangements between various project participants, rather than on the creditworthiness of the developer. The financing is typically non-recourse to the developer and is secured by the revenues of the project. Second, independent power developers have been able to take advantage of a number of new financing vehicles that have been developed in American capital markets in recent years, including new leasing arrangements, high yield or "junk" bonds, and master limited partnerships. [6] These financing techniques have not only allowed the independent power sector to become a viable industry, but--as discussed further in Chapter II--are also beginning to influence how some regulated utilities look at their financing opportunities.

New trends in utility and IPP shareownership--In addition to these changes in the types of financing being provided to the electric power industry, there have been changes in recent years in who is providing capital to the industry, including a trend toward higher levels of institutional ownership of electric utility common stock. Electric utilities were perhaps one of the last major industries where thousands of small investors that owned a few hundred shares were the dominant stockholders. Now that is changing, as institutional investors begin to play a more dominant role in trading in electric utility stocks. As Table 5 shows, the overall level of institutional ownership of utility shares rose from 19 percent in 1980 to 30 percent in 1985.

Table 5

Level of Electric Utility Shareownership by Institutions (1980-1985)

Year	Electric Utilities	All Common Stocks
1980	19	35
1981	21	35
1982	24	35
1983	23	35
1984	28	36
1985	30	39

Source: Daniel Burkhardt et al., Public Utilities Fortnightly, May 15, 1986.

The level of institutional ownership of utility shares seems likely to continue to rise. Aside from renewed institutional interest in electric utilities based on future earnings prospects, institutional investors have developed sophisticated trading strategies for utility shares that are designed to capture--or, in the case of Japanese investors, to avoid for tax reasons--their high dividend payments. The growing popularity of this use of utility shares as trading vehicles is evident from the extremely heavy trading volume of some utility shares around the time they near the dates when investors in these shares become entitled to receive their quarterly dividend payments. The higher levels of institutional ownership of utility shares may also contribute to pressures on utility managements to consider mergers or restructuring activities designed to maximize shareholder value.

Meanwhile, in the non-utility sector, there is also evidence that institutional investors are beginning to play a bigger role on the equity side of the market. Some institutions appear to see non-utility companies as an excellent way to invest in the possibility of future energy or electricity shortages, while others are attracted to these companies because of their size characteristics.[7] The levels of institutional ownership of some of the leading publicly traded non-utility power producers as of Sept. 30, 1987, are shown in Table 6.

Table 6

INSTITUTIONAL COMMON STOCK HOLDINGS IN SELECTED ALTERNATIVE ENERGY COMPANIES
(Sept. 30, 1987)

Company	Number of Institutional Holders	% Common Held by Institutions	----Thousand of shares---- 2nd Quarter Change in Inst. Holdings	Total Inst. Holdings at 9/30/87
Applied Solar Energy Corp.	8	8	-4	260
PLM Cos., Class A	9	20	15	461
Chronar Corp.	12	5	83	489
Consolidated Hydro Inc.	13	36	26	1,196
Energy Conversion Devices	12	16	-7	811
Energy Factors	17	18	-334	1,700
Geothermal Resources International Inc.	5	9	22	436
Spire Corp.	10	9	-19	329
Catalyst Energy Development Corp.	49	50	-1,264	8,365
Long Lake Energy Corp.	6	7	7	662
Magma Power Co.	31	22	332	4,534
Magma Energy Inc.	11	6	9	529
Ultrasystems	20	32	212	2,541
Thermo Electron Corp.	59	30	155	5,247

Source: CDA Investment Technologies, Spectrum: 13(f) Institutional Stock Holdings Survey.

Note: This table includes holdings by federal and state chartered banks, insurance companies, investment companies, investment advisers, pension funds, endowments and foundations with equity assets exceeding $100 million. It does not include holdings by corporations. Corporations hold large positions in several of these companies.

Chapter II: Financial Restructuring in the Electric Power Industry

A variety of economic and political forces are pushing the electric utility industry toward an operating environment characterized by more competition and less regulation. Much of the debate over the future of the industry has centered around the issue of regulatory reform. Nevertheless, regardless of what type of regulatory reform eventually does or does not evolve in the industry, a significant amount of financial reorganization and restructuring appears likely to occur. This financial reorganization is likely to take a number of forms--ranging from new financing mechanisms to merger and acquisition activity. In the words of Phillip O'Connor, former Illinois Commerce Commission chairman and now chairman of Palmer Bellevue Corp., a firm engaged in various utility restructuring proposals, there is "a certain inevitability to (utility) financial and corporate accommodations to change. They are not the causes of the movement of the electric industry into a competitive era," O'Connor notes, "only the mechanisms through which the system will smoothly, or otherwise, adapt...." [8]

Increased Competition: The Dominant Force Behind Restructuring

Regulation under attack: In recent years, the rationale for continuing to treat electric utilities as regulated monopolies has come under concerted attack. Part of this attack is grounded in the overall political philosophy of replacing regulation with market forces embodied by the Reagan administration--a philosophy that has already led to the complete or partial deregulation of most other regulated industries. Aside from a general swinging of the political pendulum toward deregulation, however, a set of underlying economic, political and technological factors specific to the electric power industry are also undermining the current utility regulatory framework. Among the most significant of these trends are: greater competition among fuels in the energy sector; changes in the power industry's cost structure and capacity situation; the consequences of the Public Utility Regulatory Policies Act of 1978; and recent technological developments in the areas of small-scale power generation and energy management techniques.

Greater inter-fuel competition--One powerful economic force behind a more competitive utility industry is the worldwide trend toward more market-based pricing of fuels. This competition has been brought on by several factors, the most important of which is the apparent weakening of OPEC in recent years as an effective price-setting cartel. As a result, world crude oil prices have fallen by more than half since they reached their peaks in 1981, promoting much greater competition among fuel sources. In addition, oil prices, being largely market-based, have declined more dramatically than natural gas and coal prices, where prices are largely set through long-tenm contracts--making oil more competitive with gas and coal in many end-use markets.

Another important factor in this increased inter-fuel competition is the stagnation of growth in overall energy demand since the early 1970s. As shown in Table 7, total U.S. energy consumption in 1986 was roughly equal to what it was back in 1973 before the first OPEC oil shock, even though the real gross national product rose 34 percent, or roughly 2.9 percent annually, during this period. Thus, the only source of growth in electricity demand for more than a decade has been increases in electricity's market share relative to other fuels. Electricity has steadily increased its share of the total U.S. energy market from 24.4 percent in 1970 to a record 36 percent in 1986, as can be seen in Table 7.

Table 7

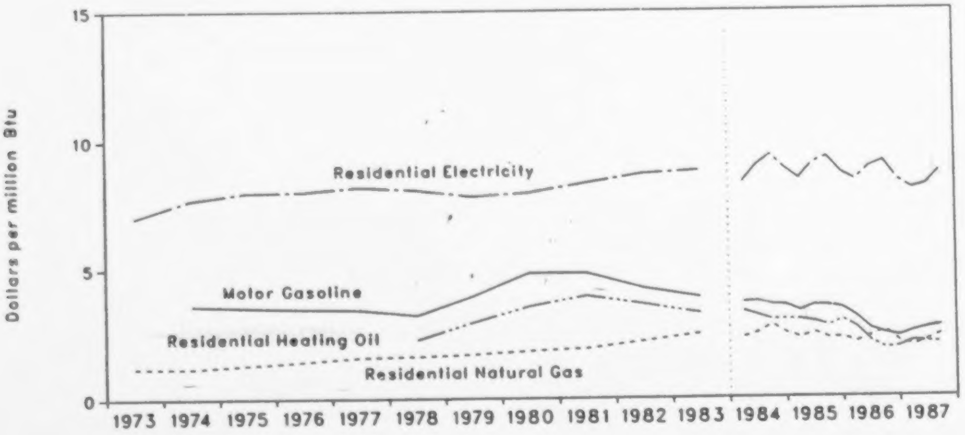
Primary Energy Consumption by Electric Utilities
(1970-1986)

Year	Domestic Energy Consumption (quads)	Primary Energy Inputs at Utilities (quads)	% of Domestic Consumption
1970	66.83	16.29	24.4
1972	71.63	18.58	25.9
1974	72.54	20.02	27.6
1976	74.36	21.57	29.0
1978	78.09	23.72	30.4
1980	75.96	24.51	32.3
1982	70.84	24.26	34.2
1984	74.06	25.94	35.0
1986	74.09	26.70	36.0

Source: Derived from Energy Information Administration, Monthly Energy Review, various issues

Figure 2

Cost Of Fuels to End Users in Constant Dollars
(1972 dollars)



Source: Energy Information Administration, Monthly Energy Review, December 1987.

One reason that electricity has been so successful in competing for market share, of course, is that it is virtually essential for some uses and is the energy source of greatest convenience in many other applications. But for other end-uses, such as residential heating and cooling and various industrial processes, electricity competes directly with primary fuel sources. In these markets, electricity is essentially a commodity that must compete on the basis of price. As shown in Figure 2, the price gap between electricity and primary fuels has widened considerably since 1980, suggesting that still further gains in market share for electricity are going to be harder for electric utilities to count on during the next decade.

Changing industry cost structure--Another fundamental factor behind arguments for greater competition in the power industry is the growing acknowledgement that economies of scale in electric power generation no longer exist for large plants, especially those over 1,000 megawatts. Inflation, lagging technological innovation in large power generating systems and costly safety and environmental regulations have combined to turn what was historically a declining marginal cost industry into an increasing cost one--where each new power plant built results in higher electric rates for consumers.

This persistent cost escalation has put severe pressures on the existing utility regulatory framework, which was basically designed to function under exactly the opposite conditions. Regulators, who for many years served primarily to decide how to allocate cost decreases among ratepayers and investors, have learned that allocating large cost increases is considerably more problematic. Passing the entire cost burden through to ratepayers, as was generally done throughout the 1970s, proved to be politically explosive and drove large industrial customers to search for alternatives. So regulators have generally turned in recent years to cost sharing schemes that require investors to share the cost burden caused by the inclusion of expensive new generating plants in the utility rate base. The results, equally unsatisfactory to many observers, have been a higher cost of capital for utilities and an overwhelming desire on the part of utility managers to avoid new commitments to build new central station power plants.

Public Utility Regulatory Policies Act--The Public Utility Regulatory Policies Act of 1978, or PURPA, provides yet another important stimulus for competition in the industry. The law was designed principally to give a boost to energy conservation and to new sources of electric power generation from such alternative sources as cogeneration, solar, wind and small hydroelectric facilities. Under the act, utilities are required to interconnect with qualifying facilities--purchasing the power these facilities produce at rates equal to their own avoided cost--and to provide backup power as necessary.

PURPA and other government incentives to encourage small power production, while creating a number of problems, have worked well from the standpoint of encouraging new sources of supply. In fact, in some ways these incentives have worked better than the authors of PURPA could have anticipated and have served to inject a considerable degree of competition into the generation side of the electric utility business. "PURPA has outgrown the expectations of its creators," notes Martha Hesse, chairman of the Federal Energy Regulatory Commission (FERC), and "has grown into a multi-billion-dollar business that is providing a majority of the new generating capacity in several large regions of the country." [9]

Although comprehensive information on non-utility power generation is still unavailable, recent estimates suggest that about 30,000 megawatts of cogeneration and small power facilities will be on-line by 1990, and that the bulk of this new capacity will be built by aggressive, entrepreneurial companies that operate in a largely deregulated environment. By the year 2000, some estimates suggest that up to 50,000 megawatts of small power will be on-line. [10] "PURPA has changed the rules of the game in the electric utility business," notes Michael Zimmer, president of the Cogeneration Coalition of America Inc., because "electric utilities no longer hold a monopolistic grip on electric generation." [11]

Technological advancements--Technological advancements involving power generation, transmission and energy efficiency technologies are still another major catalyst for utility deregulation. In the area of power generation, a variety of small-scale, modular generating systems are now available at costs that are competitive with those of large coal or nuclear generating plants. Most prominently, gas-fired cogeneration systems are available from a wide variety of vendors in sizes ranging from 20 kw to 100 MW at costs that make them an attractive alternative to utility bought power for many industrial and commercial power users.

To date, most of the cogeneration capacity in operation and under construction is associated with large industrial facilities. However, significant opportunities also appear to be opening up in the commercial sector, where some cogeneration packagers are now installing micro-cogeneration systems (20-100 kw) in commercial establishments at rates guaranteed to be below the local utility's rate schedule. In addition to cogeneration systems, small hydroelectric, biomass fueled, and geothermal plants are also competitive with utility power in some areas of the country. Meanwhile, the costs of power from other advanced technologies that could be installed in a dispersed mode--including fuel cells, photovoltaics and solar thermal systems--continue to fall. [12]

In addition to these advances on the generation side of the electric meter, perhaps even more significant technological developments have occurred in recent years in the area of energy-saving technologies that allow electricity users to reduce their power consumption. Utilities themselves are becoming relatively active in promoting such demand-side management technologies, with spending by the industry as a whole averaging about $1 billion per year. A 1986 study by the Electric Power Research Institute estimated that utility-sponsored conservation and load management programs could reduce capacity needs by the year 2000 by 80,000 MW below what it otherwise would have been. Similarly, a 1987 IRRC survey of 123 utilities found that 57 utilities that have quantified the impacts of their demand-side programs expect these programs to hold down future peak demand growth by the equivalent of more than 20,000 MW by 1995--at a fraction of the cost of building that much additional generating capacity. [13]

More importantly, an enormous array of energy efficiency measures being implemented outside the scope of utility programs are also expected to curb future electricity demand growth. Federal energy efficiency standards for major appliances were enacted in March 1987, for instance, and are projected to save the equivalent of 28,000 MW of power demand by the year 2000. [14] Similarly, recent advances in energy efficient lighting technologies could offer the prospect of a further 30,000 MW savings in electricity usage by the end of the century. [15]

Finally, significant advances in technologies will make the opening up of the power transmission grid more feasible, resulting in greater wheeling of power between utilities. Perhaps the most important development has been the widespread introduction and diffusion of sophisticated communications and computer control technologies. The development of these technologies has already fostered an increasingly active market in bulk power transfers among utilities themselves. As these communications-related technologies continue to proliferate and their costs fall, they will increase the technical feasibility of allowing real-time pricing of electricity for retail customers, allowing customers to make electricity consumption decisions based on actual electricity production costs. [16]

In addition to advances in computer and control technologies, prospects also appear bright for further breakthroughs in the area of superconducting materials. Although commercial applications for superconducting materials in the power sector are probably at least a decade away, a number of the most obvious implications of superconductors seem likely to increase competition. Superconducting wires, for example, could revolutionize the market for bulk power transfers by virtually eliminating transmission line losses. This could improve the competitive position of remote generating sources such as Canadian hydroelectric resources, coal-fired or solar generating stations situated in the desert Southwest, or ocean thermal energy facilities located at sea. Likewise, cheap electricity storage devices might greatly expand the range of generating technologies that could be competitive in certain sites.

Other Forces Promoting Utility Restructuring

Increased competition is clearly the dominant overarching trend leading toward a restructuring of the electric power industry. But a number of other factors also deserve attention as potential catalysts for an industry restructuring. In addition to the improved cash generation and financial position described in Chapter I, these factors include what some believe are the inefficiencies of the existing patchwork of utility distribution systems, undervalued utility assets, declining costs, the creation of new financial instruments, and the perception of poor management.

Inefficiencies of existing electric distribution system: The existing U.S. electric utility distribution system can perhaps best be described as a patchwork of "artificial" service territories and franchises created largely on the basis of historical accident and political considerations. At present, there are approximately 3,000 entities in the power distribution business, including 207 investor-owned utility operating companies, six federal power marketing authorities, 2,000 other publicly owned systems owned by states, municipalities, or regional governments, and another 900 or so rural electric cooperatives.

Many utility experts believe that some consolidation and rationalization of the existing electric distribution systems could yield significant gains in economic efficiency. Although economies of scale in large generating plant construction appear to have largely disappeared, there is some evidence that what have been called "economies of scope," or gains in efficiency resulting from coordination or consolidation of economic activity within a certain geographical area, have reached their limits in the electric utility business. Efficiency gains could result not only from reduced administrative expenses related to consolidating neighboring service areas, but also from reducing the amount of generating capacity reserves, particularly spinning reserves, needed to assure system reliability within a given geographical area.

Although some experts believe that much of the potential for economic rationalization pertains to consolidations involving government-owned segments of the industry, even within the 207 remaining investor-owned operating companies--which are an assimilation of nearly 2,000 private companies in existence in the 1920s--there may be further room for gains in efficiency from additional consolidation. Potential efficiency gains have been cited as the principal rationale for several recent mergers between investor-owned utilities, including the Cleveland Electric/Toledo Edison merger and the proposed mergers of Utah Power & Light Co. with PacifiCorp and Savannah Electric & Power Co. with Southern Co.

Undervalued assets: Utilities have another basic attraction from a restructuring standpoint that will become more significant in the context of a less regulated operating environment--undervalued assets. The current cost-of-service regulatory system values assets based on the cost of the asset at the time it was built minus depreciation. Under most state regulations, this historical cost-based asset value is kept even if the asset is later sold--preventing the buyer from increasing the book value of the asset to the purchase price and taking depreciation based on the purchase price. Needless to say, this system tends to value assets in a way that deviates greatly from the market-based value of the asset, especially over long periods. Although a number of regulatory proposals for increasing competition in the industry specifically exclude deregulation of such existing "embedded cost" assets, any scenario involving a more competitive industry operating environment and a greater reliance on market-based pricing seems likely to result in at least some added mobility of utility assets.

Not all utility assets are undervalued by regulation, of course. Regulation tends to overvalue some utility assets in relation to their market value, particularly new high-cost generating plants. A number of nuclear generating units are now entering service, for example, that have installed capacity costs in excess of $4,000/kw and will produce power at costs ranging from 15¢ to 20¢ per kilowatt-hour--well in excess of the prevailing market price.[17] In spite of such examples of overvalued assets, however, cost-of-service regulation tends systematically to undervalue most utility assets relative to their market value because of its emphasis on original cost. A number of examples spring to mind: fully depreciated generating plants, the transmission system, real estate and customer energy usage databases to name a few.

The notion of realizing market value for these assets is complicated by the question of ownership of these assets. Regulators may argue that much or all of the difference between book and market value of utility assets is "owned" by utility ratepayers, rather than shareholders--similar to the way they have often viewed ratepayers as having a claim on some of the profits from the non-utility businesses that many utilities have diversified into. Nevertheless, the potential for realizing greater shareholder value from undervalued assets remains one impetus behind financial restructuring in this industry.

Falling costs: Falling operating costs are another important element of the current business environment that may make utilities more attractive as restructuring candidates. The steep drop in fossil fuel prices in recent years, coupled with the general decline in interest rates, have eased some of the operating cost pressures on the industry. In spite of a flattening trend in utility rate increases, a number of industry observers believe that some of the drop in utility costs stemming from falling fuel prices, tax reform and company belt tightening measures has not yet been fully reflected in utility rates. This is significant because it could help give bidders for a utility, or utilities pursuing recapitalization plans, the leeway they need to offer regulators an important plum for approving these plans--guaranteed rate decreases or a moratorium on future increases. Needless to say, it will be nearly impossible to persuade regulators to approve utility restructurings if the result is a rate increase. Interestingly, a similar regulatory tradeoff involving less regulation in return for a guaranteed moratorium on rate increases for residential telephone customers was recently implemented by the State of Vermont.[18] This concept has also been contained in several recent restructuring proposals in the electric power industry, including ones proposed by Commonwealth Edison Co. and Public Service Co. of New Mexico.

A revolution in financing: Still another important factor that could play a role in the restructuring of the utility industry is the revolution that has occurred in the financing arena. The emergence of high yield or "junk" bond financing, in particular, gives potential acquirers the ability to raise much larger chunks of money than in the past. Salomon Brothers calculates that the percentage of new issues of corporate debt rated below investment grade rose from 11 percent in 1982 to 24 percent in 1985.[19] Big utilities that might have been "takeover-proof" a few years ago based on size alone are no longer out of reach, as is apparent from the size of some of the oil company takeovers and mergers in recent years. It is also likely that other new financing techniques, such as master limited partnerships for certain bundles of assets, may prove useful to utilities, non-utility power developers, or their acquirers as a way of getting market value for undervalued assets.

A lingering perception of poor management: A final reason why restructuring may be attractive in this industry is the lingering perception that some utilities are poorly managed. Whether accurate or not, many electric utility managers are not well regarded as managers by Wall Street or by the rest of the business community. This view no doubt springs in part from a decade of newspaper horror stories about nuclear plant cost overruns and accidents. A more fundamental reason for this perception, though, is probably related to regulation, which many managers, including some within the utility industry, believe has served to insulate utility managers from the types of competitive pressures that businesses operating in an unregulated business environment face. Leonard Hyman, vice president of Merrill Lynch Capital Markets, for instance, contends that if the industry were not regulated, poor management would be a precipitating factor for considerable merger activity. [20]

In any case, whether real or not, the perception that some utilities are poorly managed cannot help but create the impression among some business managers that they could do a better job of running an electric utility than the existing managers. Moreover, some utility managers that have been successful at coping with the changes in the industry's operating environment also appear eager for an opportunity to rejuvenate some of their less well managed neighbors.

Types of Utility Restructuring Activity

Several types of financial restructuring are beginning to emerge in the electric utility industry. Most are being proposed in response to general economic trends and by utility managements who foresee a more competitive economic and regulatory environment in the future and believe that new business strategies involving financial restructuring can help their companies prosper. Among the most significant types of financial restructuring evolving are major sale-leaseback transactions, joint venture agreements with non-utility companies, vertical disintegration, leveraged buyouts, negotiated mergers and hostile takeover activity.

Sale-leaseback arrangements: One of the most common and least dramatic forms of restructuring that utilities are increasingly considering is the use of sale-leaseback transactions as an alternative to their traditional finance methods. Utilities have used such transactions in the past for small facilities. Recently, however, they have begun utilizing lease financing in the funding or refunding of major assets. These transactions generally involve utilities selling generating plants or power lines to institutional investors and agreeing to lease back these facilities under a long term contract, typically at very attractive rates relative to existing debt.

As shown in Table 9, since the beginning of 1986, 11 power plants, including four nuclear plants, have been sold or put up for sale under sale-leaseback arrangements. The growing use of sale-leaseback transactions may not be terribly important in and of itself. But it is interesting that this financing technique is becoming increasingly popular in the utility

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Table 9

Major U.S. Electric Utility Sale-leaseback Transactions

Buyer	**Seller and plant involved**	**Price**
Not yet determined	Centerior Energy Corp (Bruce Mansfield-coal and Beaver Valley 2-nuclear)*	$1-billion (approx)
Emerson Electric,* IBM, Philip Morris	Tucson Electric Power Co (Springerville-coal)	$850-million
Shell Leasing	Deseret Generation (Bonanza-coal)	$664-million
Beatrice Financing Services, Chrysler Financial, Dart & Kraft Financial, First Chicago Leasing, JC Penney, Saks	Basin Electric Power Co-op (Antelope Valley 2-coal)	$623-million
Group of Investors (Owner Trustee, First National Bank of Boston)	Ohio Edison (Perry 1-nuclear)	$509-million
Public offering	El Paso Electric (Palo Verde-nuclear)	$396-million
Chrysler Financial, Ford Motor Credit, HEI Investment, IBM	Oglethorpe Power (Scherer 2-coal)	$395-million
Chrysler Capital, Drexel Burnham Leasing, Mellon Financial Services	Public Service of New Mexico (Palo Verde 1-nuclear)	$325-million
Drexel Burnham Leasing, General Electric Credit, Shell Leasing	Montana Power (Colstrip 4-coal)	$292-million
General Electric Credit	Portland General Electric (Boardman-coal)	$233-million

*Two-part transaction

Source: Electrical World magazine, September 1987 sector largely for reasons other than the traditional advantages to lease financing--namely the transfer of tax benefits. Rather, utilities are viewing lease financing of power plants as a full or partial solution to the "rate shock" problem caused under traditional utility accounting when a major asset enters service. The lease structure allows the rate impact of new powerplants to be stretched out over a longer period of time than is possible with traditional regulatory accounting practices, where the rate impacts are greatest in the first few years of operation. Utilities also see leases as a vehicle for turning physical assets into financial assets and diversifying their asset risks. [21] Finally, lease financing--which has been used extensively for financing non-utility cogeneration and small power projects--also allows the use of greater financial leverage and provides attractive rates, resulting in lower financing costs. Public Service Co. of New Mexico's sale leaseback for $325 million of a portion of its interest in the Palo Verde-1 nuclear unit is expected to save the utility's customers $375 million through the year 2026. [22]

The increasing use of lease financing suggests a growing awareness on the part of utility executives of the need to generate a competitive return on utility assets. Utilities "are not unaware of the risks inherent in failing to generate maximum results from the assets on their books," says David Crane, a director of the investment banking firm Babcock & Brown. "Failure to do so may result in unwanted attention from suitors." [23] It is also interesting to note that some of the utilities involved in sale-leaseback transactions, such as Centerior Energy Corp., Tucson Electric Power Co. and Public Service Co. of New Mexico, have also been involved in more extensive financial restructuring measures. Thus, the use of sale-leaseback financing by a utility may be a sign that its management is open to other ideas for restructuring.

Joint venture agreements: Another restructuring strategy being adopted by some utilities that builds on the industry's past experience is the use of joint venture agreements with non-utility companies. Utilities have long been involved in joint venture arrangements among themselves to construct major generating facilities and transmission lines. In recent years, however, some utilities have begun pursuing joint ventures with non-utility entities as a way to recapitalize certain assets or to enter new businesses.

CMS Energy Corp. is one of the most prominent examples of a utility that is using the joint venture route to recapitalize major assets. The company struggled for years in a costly and unsuccessful effort to build and license the Midland nuclear plant. Recently, under new management, CMS has formed a joint venture with Dow Chemical Co. and other investors to convert the Midland unit to a gas-fired cogeneration facility and, in October 1987, it announced an agreement to form a joint venture with Bechtel Group Inc. to own and operate the company's Palisades nuclear plant. If approved by regulators, the agreement would mark the first time that the licensee had changed for a U.S. nuclear plant.[24] In a somewhat similar case, Gulf States Utilities is pursuing a joint venture arrangement with three of its large industrial customers that would involve conversion of an existing gas-fired generating unit into a 200 MW petroleum coke-fired cogeneration facility. The agreement would help the financially strapped utility retain the load of the three industrial customers.[25]

Perhaps the best examples of utilities using joint ventures to enter new business areas are the joint ventures emerging between utilities and non-utility power producers in the area of cogeneration and small power projects. Utilities are not allowed to own more than 50 percent of the equity in cogeneration and small power facilities that are classified as "qualifying facilities" under PURPA. Thus, they must find partners in order to participate in specific small power projects. Recently, however, they have begun to form longer-term partnerships with non-utility firms as a means of increasing their involvement in this field. "I think the more progressive utilities recognize that independent power is here to stay so you might as well be a participant," says Robert Fagan, the new president of a joint venture between Combustion Engineering and a subsidiary of Florida Power & Light Co. [26] In the past two years, at least 10 such joint venture arrangements have been announced, including the following:

- In late 1985, Southern Electric Investments (a subsidiary of The Southern Co.) entered a joint venture with Chronar Corp. to build a pilot scale photovoltaic cell manufacturing facility and to market PV cells in Southern's four state service territory.

- In February 1987, Delmarva Capital Technology Co. (a subsidiary of Delmarva Power & Light Co.) formed a joint venture with Conversion Industries Inc. to develop up to nine small power facilities, mostly wood-fired, totaling 148 MW of capacity.

- In April 1987, FPL Energy Services (a subsidiary of FPL Group Inc., which owns Florida Power & Light) and Combustion Engineering formed a joint venture called Power Ventures to develop and operate cogeneration and small power facilities in Florida and the southeastern United States.

- In April 1987, Constellation Holdings Inc. (a subsidiary of Baltimore Gas & Electric) and Ultrasystems Inc. formed a joint venture to develop two wood-fired power plants and two coal-fired cogeneration plants in California. Ultrasystems also announced in mid-1987 that it has signed a letter of intent with two utilities to market 20 kW micro-cogen units in their service territories.

- In April 1987, Dominion Resources Inc. (the holding company for Virginia Electric and Power) and CSX Transportation Inc. (a subsidiary of CSX Corp.) formed a joint venture called Energy Dominion to develop coal- and gas-fired cogeneration projects in New England and the Middle Atlantic states.

- In September 1987, Atlantic Generation (a subsidiary of Atlantic Energy, which owns Atlantic City Electric) and a unit of the privately owned engineering firm Morris Rospond Group took on TriStar Ventures (a subsidiary of Columbia Gas Systems Inc.) as a third partner in a joint venture to build cogeneration projects in New Jersey, Ohio and Pennsylvania. The joint venture has six small plants under construction and 21 in various states of planning--all of which are gas-fired.

- In October 1987, Community Energy Alternatives (a subsidiary of Public Service Enterprise Group) formed a joint venture with Harbert International to buy GWF Power Systems Co. and Combustion Power Co., two wholly owned subsidiaries of Allied-Signal Inc. that are involved in the development of cogeneration and small power projects.

- In December 1987, Pacific Gas & Electric announced it was forming a joint venture with Bechtel Power Corp. to pursue non-regulated power generation projects across the country.

Utilities are also exploring the joint venture route as a possible means of financing future central-station capacity. Public Service Co. of New Mexico is a partner in a joint venture that wants to build 2,000 MW of coal-fired capacity on the Navaho Indian Reservation near Farmington, N.M.

Other partners in the project include the Navaho Tribe, Bechtel Corp. and Combustion Engineering Inc. Construction of the project will not start unless the partners are able to pre-sell at least 1,000 MW of power purchase contracts with utilities in the region. In a similar proposal, Sierra Pacific Resources, the holding company for Sierra Pacific Power, has filed an application with the Securities and Exchange Commission to set up a joint venture for the first 250 MW unit of a planned 2,000 MW coal-fired plant in northeastern Nevada. Sierra Pacific would join with 10 non-utility companies in constructing and financing the $600 million unit of the Thousand Springs project.[27]

Vertical disintegration: Vertical disintegration, or the "unbundling" of utility companies based on the functions that they perform, is another concept that a number of utilities are actively pursuing and several others have under consideration. Basically, this involves the separation of all or portions of a utility's generation, transmission and distribution functions into two or more entities that are owned and operated independently of each other.

Utilities are exploring vertical disintegration for several reasons. In one of the most prominent such proposals to date, Commonwealth Edison Co. proposed a type of unbundling that appears to be motivated largely by fear of adverse regulatory treatment for its new power plants entering service. The utility proposed in December 1986 to put three almost completed nuclear power plants in which it has invested $7.1 billion into a separate but wholly owned generating company subsidiary that would sell power back to the utility. During the first five years of operation, the subsidiary would have sold power from the nuclear units for a fee of $600 million plus the units' generating costs. After five years, the utility would be free to spin off the subsidiary. The Commonwealth Edison plan was rejected in July 1987 by the

Illinois Commerce Commission, which chiefly cited the provisions of the plan that would have eliminated prudence audits at the plants. [28]

In a more fundamental restructuring proposal, Public Service Co. of New Mexico has proposed a corporate restructuring that would entail the formation of a holding company, the separation of its operations into independent generation and distribution companies, and the placing of the distribution assets into a master limited partnership. The utility has been experiencing financial hardship largely as a result of building capacity that has left it with a 70 percent reserve margin. Under the proposed restructuring plan, the distribution company (or disco) would remain subject to state retail rate regulation, but the generation company (or genco) would be subject to regulation by the Federal Energy Regulatory Commission (FERC) under the commission's authority to regulate wholesale power sales. The strategy behind this proposal, according to the company, is to refinance the company's assets in a way that will allow it to reduce electric rates for customers while giving the utility additional flexibility to remain competitive and to pursue non-utility investments. It is also clear that the utility sees the proposal as a way to differentiate its securities based on their risk characteristics. The proposal takes into account "the recognition that there are different levels of risk associated with the different elements of the traditional utility," says David Rusk, PSNM's manager of issue analysis and corporate communications. "In general, the generation side, particularly for companies with new plant and especially nuclear plant, represents the riskiest side of the business," notes Rusk. "The distribution system has relatively lower risk. Yet, as an integrated company, the market generally attributes to your capital structure the risk associated with the riskiest element." [29]

It seems almost inevitable that more utilities will propose restructuring plans involving vertical disintegration, although the prospects for regulatory approval remain much less certain. "Many utility chief executive officers and chief financial officers are paying close attention to the efforts of PS Co. of New Mexico," says Ernest Liu, a utility analyst with Goldman Sachs & Co. [30] In fact, at least two additional utilities--Portland General Electric Co. and Pacific Gas & Electric Co.--have recently proposed reorganizing their business units along lines that would facilitate their later adoption of vertical disintegration plans. "Increasingly we will see a disintegration of electric operations into companies that emphasize either generation or distribution," predicts John Sawhill, a director of the management consulting firm McKinsey & Co. "And while there may be a limited number of completely specialized entities--such as regional wholesalers--all utilities will become somewhat more specialized." [31]

Leveraged buyouts: Leveraged buyouts are another type of restructuring activity that the electric power industry is examining. Leveraged buyouts (LBOs) involve a small group of investors buying out a company's public shareholders at a premium, usually using the company's asset base or cash flow to support a highly leveraged capital structure. LBOs usually involve the target company's existing management, but they can sometimes be undertaken by outside investors.

To date, there has not been any significant leveraged buyout activity in the electric power industry. Nevertheless, speculation about future LBO activity involving electric utilities has been quite active over the past two years. The management of Alamito Co., a wholesale generating company spun out from Tucson Electric Co. in 1984, proposed an LBO in 1985 but was eventually outbid by an outside investment group. In addition, an informal offer by an investment group for a buyout of Public Service Co. of Indiana in late 1986, which received an unfavorable response from the utility's management, was based on the concept of a cash flow LBO with management participation. There have also been reports in the financial press that FPL Group, the holding company for Florida Power & Light, rejected a friendly LBO proposal in 1986.

There is considerable debate among utility analysts over whether utility LBOs are feasible, but a number of utility experts believe that leveraged buyouts involving existing utility managers are the type of transaction most likely to succeed. Much of this speculation appears to have developed because most utilities qualify extremely well under the financial criteria used to screen potential LBO candidates. "Utilities, with their excess capacity, for the first time in our lifetime have become cash generators," says Martin Whitman, an investor involved in a restructuring effort at Public Service Co. of New Hampshire. "All utilities at rock bottom have stable earnings power. That's the stuff LBOs are made of. One-third of the utilities I looked at, I could mostly finance an LBO at today's rate by cash flow," says Whitman. [32]

Douglas Hawes, an attorney with the New York firm LeBoeuf, Lamb, Leiby & MacRae and a leading expert on the Public Utility Holding Company Act of 1935, foresees considerable regulatory opposition to utility LBOs but acknowledges their economic attractiveness. According to Hawes, what underlies "the substantial efforts currently being expended on LBO transaction proposals is that the economics are such that there is room to offer the state PSC either a reduction in rates for consumers or at least a rate increase moratorium. Moreover," says Hawes, "fully convincing arguments can be made that when there are not substantial cash requirements for construction during the period of the amortization of the LBO debt, greater leverage is not unreasonable, especially when the equity and LBO senior securities (debt and preferred) are to be held by highly sophisticated investors." [33]

Not everyone believes that leveraged buyouts will be feasible in the utility industry or is enthusiastic about their possible effects. Gary Neale, chairman of Planmetrics Inc., argues that there are valid reasons why LBOs have not come to pass. "The simplest way to finance an acquisition is with stock," says Neale. "I don't know of any valuation technique that will forecast what regulators will do in a leveraged finance situation. I can't explain regulatory risk to investors, nor can I explain that if I run the utility better, returns will drop. So it's difficult to do any kind of leveraged financing in the utility world." [34] "I suspect you may see a run at a leveraged buyout of a utility in the next few years," adds Douglas Randall, vice president for utility ratings at Standard & Poor's Corp. "There's no reason to think size would be any barrier to a leveraged buyout. It would be the largest descent of debt from high grade to high yield in the history of junk bonds," Randall says. "I wouldn't want to be served by a utility taken over in a leveraged buyout," Randall said. "They would have to raise revenues and cut expenses to finance debt. And if you have no commitment to service, there's no limit to the expenses you can cut." [35]

__Negotiated mergers__: Negotiated, or "friendly," mergers between utilities are likely to be one of the most significant types of utility restructuring activity. Interest in negotiated utility mergers by the financial community has become almost feverish. There are several reasons why friendly mergers are seen as more likely to occur than hostile transactions, including the need to share benefits among several competing constituencies and to obtain regulatory approvals. "A negotiated transaction is free of the inefficiencies and lack of mutual benefit often characteristic of a unilateral transaction," contends William Gremp, a managing director of Merrill Lynch Capital Markets, and consequently "encourages a result in which maximum potential benefits are achieved for customers, shareholders or members, and management." [36]

Although actual merger and acquisition activity has not lived up to many people's expectations, there are signs that the pace of activity has begun to quicken, as can be readily seen in Table 9. Three significant negotiated mergers involving investor-owned utilities have occurred in the past two years: a merger that was completed in 1986 in which Cleveland Electric and Toledo Edison became Centerior Energy Corp., a definitive merger agreement between PacifiCorp and Utah Power & Light that was announced in August 1987 but remains subject to regulatory approval, and a merger agreement that was announced in October 1987 in which The Southern Co. agreed to acquire Savannah Electric & Power Co. in a stock transaction.

The utility managements involved in these merger agreements generally predict that their actions were a precursor of more such activity. "We believe this step will make us a pacesetter in an industry move to fewer but larger companies," says Toledo Edison chairman John Williamson. "The key word is competition--not just between utilities but among technologies, fuels and such things as on-site generation. We need to be bigger and stronger, so we can compete in the years ahead," says Williamson.[37] Meanwhile, there are a number of examples of recent merger activity involving small utility systems. In 1986, for instance, Iowa-Illinois Gas & Electric bought Sherrard Power Co., an all-requirements wholesale customer of Iowa-Illinois that served about 13,000 customers. Similarly, in the public sector, the Omaha Public Power District, the largest electric utility in Nebraska, is considering a merger with the Norris Public Power District, which serves about 12,000 customers in the southeastern part of the state.[38]

Opinion seems sharply divided among other industry executives as to whether much merger activity is likely. A few utility executives have publicly predicted a spate of merger activity. Jerry Geist, chairman of Public Service of New Mexico, warned an audience of utility executives at the 1987 Edison Electric Institute annual conference that "if we don't restructure our industry ourselves, someone will do it for us." The industry "has a truly astonishing number of small, vertically integrated companies that are ripe for disaggregation and consolidation," said Geist. "My guess is that this...path will become more attractive once regulators and customers realize the magnitude of possible cost savings from the vertical disaggregation and horizontal consolidation implicit in this path," he added. [39]

But other industry executives feel that the merger issue is being kept in the spotlight mainly by investment bankers and consultants trying to drum up business, and that there will be relatively few utility mergers. Moreover, industry surveys suggest that, as a whole, industry executives are relatively unconcerned about mergers and other structural issues. For instance, a survey of top executives from 60 utilities in 1987 by Cresap, McCormick & Paget, a Chicago-based management consulting firm, found that concerns about merger activity ranked well below a number of other strategic issues.

Just as opinions are sharply divided among industry executives on the issue of mergers, so too is there little agreement among utility analysts and investment advisers on the subject. Some industry analysts predict a tremendous wave of consolidation within the next few years. Edward Tirello Jr., senior utility analyst at Shearson Lehman Brothers, argues that "companies with the cheapest source of power generation and the strongest transmission lines will take customers away from weaker neighbors, thereby forcing the industry to consolidate." Tirello predicts that of the 150 major investor-owned utilities in the nation, "five years from now there will only be 50." [40]

Other analysts foresee some merger activity, but are more cautious in their appraisal of the number and timing. "We'll see lots of idiosyncratic situations regarding merger and buyout activity," says Gregory Enholm of

Table 10

Chronology of Significant Utility Merger and Takeover Events

- June 1985: Cleveland Electric Illuminating Co. and Toledo Edison Co. announced their intention to merge. In April 1986, the merger was finally consummated, resulting in the formation of a holding company called Centerior Energy that acquired the stock of both operating utilities.

- November 1985: The management of Alamito Co., a wholesale power generation company previously spun off from Tucson Electric Co., proposed to take the company private in a leveraged buyout. In 1986, after a protracted bidding war, a subsidiary of Catalyst Energy Corp. outbid Alamito's management and other bidders, gaining control of Alamito.

- 1984 through 1987: UtiliCorp United Inc. made a string of small acquisitions. Over the past three years, UtiliCorp acquired three small gas utilities and two small electric utilities--West Virginia Power, and West Kootenay Power & Light.

- October 1986: An investor group including former EPA administrator William Ruckelshaus and former Illinois Commerce Commission chairman Philip O'Connor reportedly made an informal cash bid of $17 per share for Public Service Co. of Indiana stock. The company was apparently not receptive to the proposal and it was dropped.

- December 1986: Millionaire investor David LaRoche made a hostile tender offer for a controlling interest in Newport Electric Co. The utility responded by reorganizing as a holding company, NECO Enterprises, after LaRoche's offer failed to attract a majority of the outstanding shares. LaRoche commenced a second tender offer for NECO's shares in March 1987 and, by late July, held 50.1 percent of NECO's common shares.

- July 1987: Thomas Bruce, a Boston stockbroker, announced he was trying to garner support from anti-nuclear groups for a takeover of financially beleaguered Public Service Co. of New Hampshire, the chief owner of the Seabrook nuclear power plant. Two other groups of PSNH debtholders also began attempts to gain control of the utility.

- August 1987: PacifiCorp and Utah Power & Light Co. agreed to merge, citing prospects for increased efficiencies from operating as a combined company. The merger is subject to regulatory approval.

- September 1987: Pacific Gas & Electric Co. submitted a proposal to the Sacramento Municipal Utility District (SMUD) to buy all of SMUD's facilities and to close down the troubled Rancho Seco nuclear plant.

- October 1987: Southern Co. agreed to acquire Savannah Electric & Power Co. for stock at a price of almost twice Savannah Electric's book value.

Source: Investor Responsibility Research Center

Salomon Brothers. "It will probably follow the same pattern we saw with diversification, with a few deals at first and then more happening later." [41] "Some utilities will be driven to "strategic" mergers that will offer opportunities for improved performance in terms of operations, finance, administrative savings, strengthened management and generation planning, agrees management consultant John Sawhill. But Sawhill predicts that merger activity will not be widespread, because many utilities will improve performance without resorting to formal mergers and because of the "added difficulty of justifying paying a premium for a company in a regulated industry." [42] "I don't expect wholesale mergers because the regulators are watching," adds Leonard Hyman of Merrill Lynch. "But there will be some opportunities," Hyman says--including "shotgun marriages" for troubled utilities and the possibility of takeovers of portions of utilities if investor-owned utilities split themselves into generating companies and distribution companies. [43]

A number of other utility analysts and consultants are even less sanguine about the prospects for many utility mergers. Merger and takeover talk has "been very overhyped," contends Drexel Burnham Lambert managing director John Kellenyi. "There will be some merger and acquisition activity, but we're more likely to see internal restructuring," says Kellenyi, and "the pace will be evolutionary, accelerated or retarded by key regulatory events." [44] If utilities "haven't learned how to play the regulatory card well and the consumer card well, then there probably will not be a merger," adds Jassi S. Cheema, senior vice president of Theodore Barry & Associates. From Cheema's perspective, the industry is probably heading for more "quasi" mergers--informal arrangements to plan capacity and dispatching needs in response to "least-cost" planning initiatives, rather than true mergers. [45]

Hostile mergers and takeovers: Another type of restructuring that may play a role in the utility industry is hostile merger and takeover activity. At present, two significant hostile takeover attempts are developing on the investor-owned side of the industry: an attempt to take over NECO Enterprises, the holding company for Newport Electric Co., and attempts by several parties to gain control of financially troubled Public Service Co. of New Hampshire.

In the case of NECO Enterprises, private investor David LaRoche began pushing a takeover attempt in December 1986. LaRoche, who was reported to be interested in a certain waterfront parcel of undeveloped real estate owned by the utility, undertook two partial tender offers to NECO's shareholders in 1986 and 1987 and, when combined with purchases of the company's stock on the open market, was able to secure ownership of 50.1 percent of NECO's common stock by July 1987. Then, in December 1987, LaRoche announced that he had reached an agreement to sell his controlling interest in NECO to Eastern Utilities Associates (EUA), a utility holding company headquartered in Boston. EUA reportedly wants to acquire the remainder of NECO stock in a friendly merger, but it would launch a tender offer if NECO did not agree to an acquisition. Despite the antitakeover measures that NECO Enterprises has in place, including its organization as a holding company, LaRoche's majority ownership position meant that it was inevitable that he would have eventually acquired control of NECO, says PUHCA expert Douglas Hawes. "If an individual has sufficient resources to acquire utility shares without creating an acquisition vehicle and leveraging it, '35 Act problems can be avoided," notes Hawes. "That is because the '35 Act only applies to holding companies and a natural person is virtually the only person that does not constitute a 'company' as defined in (PUHCA) Sec. 2(a)2." [46] If successful, a takeover of NECO Enterprises would be notable in that it would be the first hostile takeover of an investor-owned utility in several decades.

In a more fluid and less organized situation in the State of New Hampshire, several groups appear to be considering hostile takeover or restructuring attempts at Public Service Co. of New Hampshire (PSNH), which is also saddled with a completed nuclear power plant that has been unable to operate because of fears relating to evacuation procedures. In a July 1987 article in the Boston Globe, Thomas Bruce, a stockbroker with Paine Webber Corp. in Boston, said he was trying to gain the support of anti-Seabrook activists for a takeover of Public Service Co. of New Hampshire. In October 1987, however, the utility decided to default on a $37 million interest payment, perhaps paving the way for its mortgage bond and debenture holders to force it into involuntary bankruptcy. The debt payment suspension has resulted in a recapitalization plan being proposed for PSNH by Consolidated Utilities and Communications Inc., a New York firm representing a consortium of PSNH bondholders.

Public versus private power takeover battles: A final type of restructuring activity underway is a variety of battles involving attempts by city or state governments to gain control of investor-owned utilities and attempts by investor-owned utilities to gain control of publicly owned utilities. Interestingly, the catalyst for a number of these takeover situations appears to be a series of troubles related to nuclear plant construction or operation.

In New York, Gov. Mario Cuomo and the state legislature are pursuing an effort to allow a new public power authority to take over Long Island Lighting Co. (Lilco) as a means of assuring that the Shoreham nuclear plant will never operate. The state agrees with county and local officials that it would be impossible to evacuate the area surrounding the plant in the event of a nuclear accident. In 1986, New York passed a law in 1986 creating a Long

Island Power Authority (LIPA) to study whether it could provide power at rates cheaper than Lilco and, if so, empowering it to acquire the utility either through negotiations or through condemnation of the utility's property through eminent domain. At present, the Lilco takeover battle is being fought primarily on the issue of whether a state takeover would result in lower rates to electricity consumers. The state has commissioned studies which purport to show that rates would be lower under a LIPA takeover, while Lilco has released studies arguing the opposite. A decision on the matter is expected by early 1988, although many analysts remain skeptical of any quick resolution of the issue.

A number of city governments are also looking at the option of municipalization of investor-owned electric distribution systems. In Chicago, city officials are reported to be mulling several options with regard to buying out or bypassing Commonwealth Edison's power system. The city's franchise agreement with the utility expires at the end of 1990 and city officials are unhappy with electric rates, which have risen six times in the past 10 years and threaten to go much higher as Commonwealth Edison tries to include the costs of several new nuclear units in its rate base. The late Chicago mayor Harold Washington had called the formation of a municipal power agency "one of the most challenging options" for the city.[47] City officials in New Orleans; Gilbert, Ariz.; and Albuquerque, N.M., are also studying the municipalization option.

In addition to these situations involving possible takeovers of investor-owned utilities, there appears to be considerable potential for what are essentially takeovers of municipally owned and cooperative electric systems by the investor-owned sector. One such situation is developing in California, where Pacific Gas & Electric proposed a buyout of the Sacramento Municipal Utility District (SMUD), one of the largest municipal electric systems in the country. SMUD has faced considerable difficulties stemming from the prolonged outage of its Rancho Seco nuclear plant. Rancho Seco has been out of commission since December 1985 after an overcooling incident shut the plant down. SMUD has been struggling to restart the reactor--which has a trouble-plagued history--but meanwhile has watched its rates rise 60 percent since 1985 as it has been forced to replace the lost power with purchases from other sources. In September 1987, PG&E made a proposal to SMUD to "consolidate" SMUD into the PG&E system while permanently closing the Rancho Seco plant. Public and private reaction to the PG&E plan by SMUD officials and its board was negative, however, and PG&E withdrew its proposed bid in January 1988 citing SMUD's "failure to give serious consideration" to its consolidation proposal. [48] SMUD is reportedly examining a number of options ranging from operating Rancho Seco, to selling it or converting it to a gas-fired facility, to a sale of all of SMUD's generation and transmission assets. [49]

Similarly, Virginia Power is attempting to persuade seven municipal utilities to enter into joint studies on merging into the investor-owned utility. Meanwhile, legislation has been introduced in South Carolina that calls for sale of the state-owned Santee Cooper generating and distribution system to one of the state's investor-owned utilities. Proceeds from the sale, estimated to range as high as $4 billion, would form an endowment to help finance education budgets and universities in the state. [50]

Like the issue of utility mergers, the question of whether hostile takeovers are likely to become a common occurrence in the utility industry provokes intense debate among industry analysts and consultants--although those believing that there will be few hostile takeovers are a distinct majority. The issue that appears to separate those analysts who believe takeover activity is likely from a majority of their peers is how stifling the regulatory obstacles to takeovers will be.

Many analysts see these regulatory hurdles being too onerous to overcome for most would-be utility acquirers. John Sawhill of McKinsey & Co., for example, says that the regulatory and legal barriers to takeovers will prove formidable and that while "you might see an outsider buy one electric utility, because of the company's cash generation, you will not see the amount of takeover activity suggested in the articles I've read." 51 "A close look at the facts shows that utility takeover talk is mostly smoke and only a little fire," adds Douglas Hawes. Hawes sees time as perhaps the biggest impediment to utility takeovers. "The biggest problem is time, which is the biggest and best defense of a target. I just don't think there will be many attempts at leveraged buyouts or takeovers in this industry, even by other utilities," says Hawes." 52

This view that regulatory and other obstacles to utility takeovers will prove prohibitive is by no means universal, however. "There are much greater obstacles to taking over utilities, with layers of regulation," notes Evan Silverstein, a former utility analyst at L.F. Rothschild, Unterberg, Towbin who now manages the utility investments of the Bass Brothers. "But they won't be total obstacles, if [an acquirer] can show stockholders such a move is in their best interest," says Silverstein. 53 "I think we're going to see several hostile utility takeover attempts," agrees Marc Hecker, an attorney at Skadden, Arps, Slate, Meagher and Flom, "and I don't mean Alamito-type deals, I mean old-fashioned takeover attempts." 54

Chapter III: Investment Community Views on Utility Restructuring

The following findings are based on a series of interviews with members of the investment community who have substantial experience with the financing of the electric utility and small power industries.

- Much of the financial community sees large industrial customers as the primary destabilizing influence on the existing utility system. This influence takes a number of forms, including industrial cogeneration, the threat to move facilities between service territories or to add new facilities and jobs where utility rates are low, and the political and social clout to affect how rates are set. Investors believe that industrial customers have developed a new mindset toward utility rates--a mindset that views these rates as a variable that can be altered--that will be impossible to turn off. Investors expect the next major area of confrontation between industrial customers and utilities to center around the issues of wheeling between industrial facilities and access to the transmission grid.

- Many investors say that the government should take a long hard look at what has happened in the electric power industry in recent years and why before they embark on any major changes in the industry's existing regulatory system. There is considerable wariness about need for major changes and about the likely results of virtually any type of massive government rewrite of utility regulation. Investors argue that lawmakers and regulators tend to view the industry's situation through a prism that reflects past, rather than current, problems and that it is unrealistic to suppose that someone will devise a perfect formula for fixing the industry's current problems. Some investors are very skeptical that competition can serve as a substitute for regulation in the electric power industry unless regulators are willing to do away with utilities' obligation to serve all customers. These investors say that the government is currently a "destabilizing" force in the industry, when it should be working to stabilize the system. Other investors welcome the prospect of a less regulated environment for utilities and believe that the market should be allowed to dictate the future direction of the industry while government helps the process along by providing flexibility during the transition phase through actions such as a loosening of the restrictions in the Public Utility Holding Company Act.

- To the extent that changes are made, there appears to be some preference among investors that these changes be made at the national level, rather than allowing each state to operate with a different set of rules. In general, investors feel that the Federal Energy Regulatory Commission (FERC) is fairer to investors than most state regulatory commissions. They also tend to view the FERC as less politicized than the Congress and prefer that any overarching changes in utility regulation be made under FERC guidelines, rather than through congressional action. Similarly, while they would prefer to see the government's involvement in regulating financial restructuring activity kept to a minimum, investors tend to prefer that any regulation of this type of activity be done at the federal level--either through FERC or through the SEC--rather than through state PUCs. A minority of the investors interviewed preferred that state regulators take the lead in this area, fearing that FERC or the Congress might impose overly specific rulemakings that would limit the flexibility of utilities to respond to local conditions.

- Some institutional investors are skeptical of the common assumption of a capital availability problem in the electric power industry. Some investors believe that utilities and their investors misunderstood the nature of the regulatory "social compact" from the beginning. They say that regulators promised only to allow utilities to recover the lower of actual costs or market price, and that now a period of adjustment is needed as the market price of power has fallen below its cost for some high-cost producers. Other investors do believe that regulators have indeed broken the "social compact" with utilities and their investors. Nevertheless, most investors do not believe it will be difficult for the industry as a whole to continue to raise substantial amounts of capital for the next cycle of plant construction--albeit in smaller increments than the 1,000 MW plants of the last cycle. Rather, investors tend to view any capital availability problems as related to certain readily identifiable segments of the industry, including:

  1.) Extraordinary and perhaps temporary situations--especially those involving utilities that have well-publicized financial difficulties relating to troubled nuclear plants such as Long Island Lighting Co. and Public Service Co. of New Hampshire.

  2.) Utilities that must operate in states with elected regulatory commissions that may view utility rates as a political matter.

  3.) Small power producers (either QFs or IPPs) that lack a sufficient track record, reputation and/or capital base to provide a sufficient level of comfort to investors. This would not apply to large, established independent power producers or consortiums involving healthy utilities.

- A number of investors believe that some of the state regulatory and pricing concepts currently being experimented with will prove unworkable. There is some skepticism that the PURPA model can work in a competitive operating environment where buyback rates have fallen as low as 3-4¢ kwh. There is even more skepticism that many competitive bidding schemes for procurement of new generating capacity will prove workable--primarily because they result in contract awards based almost entirely on price, without proper attention to the qualifications of the bidders or to the service aspects of power supply. One major investing institution stated that "of the four competitive bidding awards made so far, none are financeable."[55] Investors also note the trend toward utilities demanding that non-utility projects be subject to utility dispatch and wonder how people expect them to provide non-recourse project financing for projects whose revenue streams are subject to utility dispatch. Some investors believe that the previous system of negotiated contracts was a superior system because it allowed greater flexibility than do competitive bidding systems.

  Some investors also worry that the competitive bidding concept, although it is supported by many utilities, will ultimately come back to haunt utilities if they end up short of power. Investors believe that if utilities award power purchase contracts to unqualified bidders, these projects will eventually fail, and regulators will attempt to penalize the utilities for not adequately meeting their service needs. Investors strongly believe that active utility participation in the construction of new generation provides a level of comfort to investors that is very important to the financing of substantial projects. The believe that joint independent power projects involving utilities and "name brand" construction and engineering firms or other non-utility power developers will have little trouble obtaining attractive financing.

- Regarding the five regulatory scenarios outlined by the Office of Technology Assessment, there is considerable doubt among the majority of financial institutions interviewed that any of the scenarios involving new rules would be superior to the status quo from the perspective of reducing risk to investors or providing greater capital availability to the industry. Investors tend to regard fully integrated utilities that retain a monopoly on all aspects of the business as the least risky proposition. The general perception is that each of the OTA scenarios involving expanded competition on the generation side of the business or greater transmission access progressively chips away at the monopoly franchise concept, thereby subjecting the investor to greater market risk. Investors say that each step down this path of increased market risk would have negative implications for utility credit ratings and would require commensurate increases in the return required by investors in order to participate in financing the industry's capital needs. OTA scenarios 4 and 5 would result in very high cost financing, investors say, with the total returns required by investors under these scenarios equal to the returns for fully competitive industries using equity or junk bonds to obtain capital.

A minority of investors interviewed reject the above thesis, arguing that most of the business risk in the electric power industry has arisen from fundamental changes in the external environment that cannot be undone. Regulation has changed from a risk mitigator to a source of added risk, these investors acknowledge, but the reason is not that regulators have just decided, en masse, to punish investors, but that external conditions have forced them to take new approaches. These investors tend to see opportunities in the changes taking place, and to believe that hoping for a return to a monopolized, risk-free investment atmosphere in the electric industry is akin to hoping for a return of the dinosaurs. They maintain that if the policy objective is to provide a stable environment for bringing new capacity on line, a competitive system will do it better than an attempt to resurrect the old regulatory compact.

- There is some difference in the perspective of equity and debt investors with regard to the willingness to provide capital to the industry under a changed regulatory system. In general, equity investors believe that any set of rules changes will have a selective impact on different players in the industry--thereby providing new investment opportunities as well as investments to avoid. Equity investors are looking to find "an angle" on the industry to play. Equity investors believe that most of the OTA scenarios would have a differential effect on the industry--helping low cost producers at the expense of high cost producers. Equity investors would look to profit from this differential impact by analyzing how different companies would be likely to fare under the new set of rules and shifting their investments toward those companies that could take best advantage of a more competitive environment.

Debt investors, on the other hand, tend to see virtually any set of rules changes presently under consideration--including all of the OTA scenarios except the status quo--as resulting in an increase in debtholder risk with no increase in reward. They note that huge amounts of utility bonds are outstanding, and that any regulatory change that weakens the monopoly franchise and makes the industry more risky can only result in a devaluation of these outstanding utility bonds based on the increased possibility of defaults. In other words, utility debtholders tend to see the existing regulated monopoly system as the most stable possible operating environment for utilities, and to see any movement away from this concept as resulting in increased business risk and declining credit quality. And unlike investors on the equity side, debt investors say there would be no "winners" in this new game, because many utility debt issues would be downgraded and few, if any, would be upgraded. From a credit ratings standpoint, one analyst believes that under the more competitive business conditions that would result from most of the OTA scenarios, utilities would have no choice but to increase the levels of equity in their capitalization structures if they wanted to maintain their existing credit ratings.[56]

- Investors tend to see utility financial restructuring as a symptom of an industry that is encountering financial problems resulting from excess capacity. They believe that more financial restructuring activity will occur and that it has the potential to result in improved industry efficiencies. Some investors believe that financial restructuring can, over time, make a major contribution to solving the fundamental problems faced by high-cost producers in the industry. They see sale-leasebacks, vertical disintegration, mergers and other restructuring activities eventually narrowing the cost-of-service differences among utilities. Other investors, however, dismiss financial restructuring as little more than a shell game that will have little impact on solving fundamental problems. From a credit quality perspective, investors say that debt-financed restructurings would have negative credit implications, but mergers between equally rated utilities would probably not have much impact on credit ratings. Mergers could also have positive implications for the merging utilities (especially if they resulted in greater market power) while having negative implications for the competitors of the merged entity. Utility sale-leaseback deals will have negative implications for credit quality unless the full proceeds are used to pay down other debt, analysts say, because the lease obligations will be treated as debt equivalents.

- There also appear to be some philosophical differences between investors who have participated in the power industry chiefly through financing non-utility power developers and those who provide capital primarily to utilities. Utility investors tend to see government involvement in the industry through regulation as a safety net that, except where it has become overly politicized, lessens their risk. Investors in non-utility projects, however--while recognizing PURPA as being important to get the industry launched---now see further deregulation of the electric power arena as offering the greatest opportunities for growth in the non-utility power generation business. [57]

- Members of the financial community believe that providing project financing in the electric power area has essentially become a highly competitive commodity-type business. They see the field attracting a large number of new financial institutions that have varying motives for getting involved in this area. They say that Japanese and European financial institutions, many of which have ties to manufacturing companies, have become quite active in the small power and utility financing area. Some investors see this influx of foreign capital as a positive development, resulting in lower financing costs for all participants in the industry. Others, particularly major domestic lenders, complain that foreign investors are undercutting their business and are doing deals at below-market rates as a way of buying market share in the business and of acquiring knowledge that will allow them to become more competitive manufacturers of technologies developed in the United States.

Appendix A

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Appendix B

Glossary of Investment Terms

Asset- or credit-based financing--Financing where funds are invested or lent based on the existence of physical assets that can serve as collateral. Utility mortgage bonds, where the utility's physical assets serve as collateral, are an example.

Financial leverage--The use of borrowed money in a transaction. Highly leveraged financings can involve up to 90 to 100 percent debt financing, with little or no equity component.

Junk bonds--High coupon rate junior debt securities that typically have below investment grade credit ratings.

Master limited partnership--Publicly traded partnerships that offer the advantages of partnership-type investments (direct ownership of assets and a proportionate share of income, losses and tax deductions generated by the partnership) while providing the liquidity that is often lacking in conventional partnership investments.

Project financing--A type of financing where the lender looks primarily at the cash flow and assets of a specific project, rather than at the creditworthiness of the borrower. Powerplant project financings rely on tightly drawn contractual arrangements among the various participants in a project--such as the project developer, fuel supplier, vendors and constructors and the entity purchasing the power.

Recapitalization--Financing activities that change the capital structure of a company or an asset.

Restructuring--A somewhat catch-all phrase encompassing activities designed to change the organizational or financial structure of a business.

Sale-leaseback--A financing arrangement where one party--typically a bank, insurance company, corporate financing subsidiary, or leasing company--purchases and finances an asset from the owner and leases it back to the owner/operator under a long-term contract, with specified rental payments to cover interest and principal on any debt in the capital lease structure, plus a nominal cash return on the equity.

Tombstone advertisements--Box-shaped advertisements run in financial newspapers and magazines by financial firms involved as principals or advisers in securities offerings or other financings.

Notes

1 Scott Fenn, Mergers and Financial Restructuring in the Electric Power Industry (Investor Responsibility Research Center, Washington, D.C., 1988); and Scott Fenn, Institutional Investment in Renewable Energy Technologies (Investor Responsibility Research Center and Renewable Energy Institute, Washington, D.C., 1987).

2 Scott Fenn, America's Electric Utilities: Under Siege and in Transition, (Praeger, New York, 1984), p. 31.

3 See for instance Electrical World, "1987 Annual Industry Forecast," September 1987, p. 42.

4 See for instance, Scott Fenn, Douglas Cogan and Susan Williams, Power Plays: Profiles of America's Leading Renewable Electricity Producers (Investor Responsibility Research Center, Washington, D.C., 1986); and "Profile of Cogeneration and Small Power Markets," Hagler Bailly & Co., 1987.

5 Several problems are inherent in the tombstone ad methodology used by NAESCo. First, many financings in the private placement market, including some large ones, never appear in any tombstone ads and hence are never included in the NAESCo totals. Second, some financings for the same project may be advertised by several of the underwriters or principals, possibly resulting in double-counting. Likewise, use of short-term construction loans or bridge financing may also result in double-counting.

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[16] For a discussion of the importance of this concept in the residential market see "Inside the Smart House," EPRI Journal, November 1986;

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[22] "Sale/leaseback Deals Providing Utilities New Capital and Lower Financing Costs," Electric Utility Week, Jan. 13, 1986, p. 2.

[23] David G. Crane, "Behind the Increasing Use of Lease Financing by Utilities," Public Utilities Fortnightly, Feb. 19, 1987, p. 24.

[24] Paul Ingrassia, "CMS to Enter Nuclear Venture With Bechtel," The Wall Street Journal, Oct. 8, 1987, p. 8

[25] "In Reversal, FERC Gives Go-ahead to GSU/Industry Cogeneration Venture," Electric Utility Week, May 18, 1987, p. 16.

[26] Donald Marier and Larry Stoiaken, "The Utilities: Partners or Adversaries, Alternative Sources of Energy, May/June 1987, p. 18.

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[28] Bill Richards, "Commonwealth Edison's Plan to Form Nuclear-Plant Unit Rejected by Agency," The Wall Street Journal, July 3, 1987.

[29] "'Unbundling' Proposal by PS New Mexico Confines PSC Regulation to Distribution," Electric Utility Week, March 2, 1987, p. 1.

[30] Paul Duke Jr., "PS New Mexico Weighs Partnership For Its Electric Distribution System," The Wall Street Journal, March 5, 1987.

[31] "Pressures of Competition Seen Leading to 'Disintegration' Of Industry," Electric Utility Week, April 21, 1986, p. 7.

[32] Barry Stavro, "High-voltage Action," Forbes, May 5, 1986, pp. 48-49.

[33] Douglas Hawes, "Utility Takeovers: Considerable Talk, Not Much Action," The Legal Times, Oct. 20, 1986, pp. 13-16.

[34] Comments at Institute for International Research Utility Restructuring conference, New York City, Sept. 21, 1987.

[35] "Perceived Threat of Takeovers Spurs 17 Utilities to Set 'Shark Repellent'," Electric Utility Week, May 12, 1986, p. 1.

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THE SITING OF EHV ELECTRIC TRANSMISSION LINES

MAY 1988

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TABLE OF CONTENTS

Executive Summary..........1

Introduction..........3

Overview of the EHV Transmission Network..........4

The Transmission Bottleneck..........9

Siting Procedures..........13

- Capacity Planning..........14
- State Certification and Licensing..........16
- Local Permits and Approvals..........20
- Permitting Transmission Lines Across Federal Lands..........21
- Permitting Transmission Lines Across Tribal Lands..........25
- Multi-state Siting Efforts..........27

Impediments to Transmission Line Siting..........30

- Obstacles to Transmission Line Approval..........30
- Jurisdictional Complexities..........35
- Lack of Multi-state Coordination..........37

Interest Group Perspectives..........39

- Utility Companies..........39
- Government Regulators..........40
- Landowners and Affected Populations..........41
- Ratepayer Consumer Groups..........42
- Environmental Organizations..........42
- Energy Systems Advocates..........43

Options to Improve Transmission Line Siting..........45

- Expanding the Planning Process..........46
- Streamlining the Regulatory Approval Process..........48
- Involvement of Multi-state, Federal, or Independent Agencies..........50
- Enhanced Public Participation..........52

Three Case Studies..........53

- The Coal Creek Project..........54
- The Ole Project..........59
- The Washington DC Loop..........64

Conclusions..........68

Bibliography..........71

Footnotes..........72

EXECUTIVE SUMMARY

The long distance transmission of electricity has increased significantly in recent decades. Power generation and sales predicated on long distance transmission can improve the financial positions of both the selling and buying utilities, absorb excess generating capacity, enhance system reliability, equalize power costs among regions, promote national environmental or energy security objectives, and postpone the construction of expensive new power plants. Thus, expanded use of long distance EHV transmission is a pivotal concept underlying many utilities' current electricity supply strategies and several proposals to restructure the industry to promote competition.

Transmission capacity in some portions of the electrical grid is already strained by high usage and the pace of construction of new power lines has fallen over the past two decades. One possible reason for this is that the many licensing and certification processes required to site new transmission line projects can impede power line construction and sometimes lead to abandonments regardless of the merits of the projects.

Long range planning efforts at the state level tend to focus on power generation issues, leaving interutility sales and long distance transmission issues understudied. Gaining approval of specific transmission line projects by state regulatory agencies is a complicated process frequently requiring the filing and review of multiple applications. Constraints imposed by state utility laws and regulations hamper decisionmakers as they review large interstate transmission line proposals.

Involvement of many local governmental agencies, the courts, and the federal and tribal governments further complicates the siting process and can lead to jurisdictional conflicts. The lack of multi-state siting procedures and coordination among federal agencies and agencies in different states further encumbers the siting of interstate power lines. A variety of interests groups have effectively entered the siting process for new transmission lines, although their involvement has frequently added to the time required to complete siting and to the complexity of the process.

Proposals to improve the siting process for new transmission lines include developing more information about transmission needs in the long range planning and application review processes, streamlining and clarifying state regulatory agency review processes, broadening multi-state siting efforts, and increasing public participation. Standardizing and expanding reporting requirements, increasing inter-agency communication, developing clear and consistent evaluation criteria, and creating new regulatory entities empowered to make final siting decisions could help achieve these objectives.

INTRODUCTION

From the time the electric light bulb first illuminated Thomas Edison's laboratory in 1879, the transmission of electricity has been inextricably linked to electrical generation and use. With few exceptions, electrical transmission, utilizing alternating current (AC) or direct current (DC) electrical fields, have connected sources of electricity with power consumers.

As the electric utility industry has grown, technological advancements have permitted the construction of extra-high voltage (EHV) transmission lines capable of moving large volumes of electricity over long distances. This trend has accelerated in recent decades as long distance transmission has increased and the network of EHV transmission lines has broadened. The rise in long distance transmission promises to continue under a number of proposals to restructure the electric utility industry, assuming of course that transmission line construction keeps up with growing demand for long distance transmission services. The validity of this assumption is crucial to the fate of such restructuring plans, however, because transmission line construction projects can face an increasingly complex framework for regulatory agency approval and considerable public opposition.

This paper examines the procedures for siting and building EHV transmission lines in the United States. It explores the impediments to power line construction and outlines the history of some recent transmission line projects which have experienced construction delays. Finally it discusses the often conflicting perspectives of interest groups towards EHV transmission, and some proposed remedies to alleviate the difficulties which face transmission line construction projects.

OVERVIEW OF THE TRANSMISSION NETWORK

For most of the past century, electricity has been carried from producer to consumer by short-distance, low-voltage transmission and distribution lines. Nearly all electricity today is still carried to the final point of use by low-voltage lines. Beginning with the installation of the first extra high voltage (EHV) 345 KV line in 1952, however, more and more electricity has travelled farther distances in the United States on EHV lines. These lines generally connect sources of power generation with power distribution networks of low-voltage lines near the points of end use.

Total circuit miles of EHV lines with a voltage greater than 250 KV grew from 62 miles of AC EHV lines in 1952 to 67,418 miles of EHV AC lines and 1745 miles of EHV DC lines in 1984.[1] By the end of 1986, the figures stood at 71,629 AC miles and 2293 DC miles, with an additional 8,775 miles of EHV lines scheduled for completion by 1996.[2] As technology continues to evolve, higher voltage transmission lines are being built. More than 2,000 miles of AC lines with a 765 KV capacity now exist as well as about 1,300 miles of 500 KV direct current lines.[3]

The expansion in the grid of long distance, high-voltage transmission lines has permitted increased short-term sales of large quantities of electricity from one electric utility to another. These transactions, called economy sales, represent a broadening of the historical pattern of each utility generating power solely for customers within its franchised service area or for sale to another utility on a long-term, contract basis. Economy sales to date generally reflect a situation of unplanned excess generation capacity, but the sales could continue over the long term if new capacity is designed specifically with increased economy sales in mind.

Between 1976 and 1983 power sales among utilities grew 67% faster than sales to the ultimate end users of electricity, for example residential and commercial customers. By 1983, the sales of power among utilities had grown to a $43 billion annual business.[4] Interutility sales, which accounted for just 5.6% of total generation in 1953, constituted 20.1% in 1983.[5] By 1986, at least 14% of generated electricity crossed at least one state border between the points of production and use.[6]

Economic and other considerations have convinced a number of utilities to build new EHV power lines to take fuller advantage of long distance transmission capability facilitated by extra high voltage technology. For example, EHV lines reduce electricity losses which can consume up to 10% of generated electricity, thereby improving the economics of long distance transmission compared to transmission over lower voltage lines. Moreover, new transmission lines can improve the overall efficiency and reliability of electricity transportation which in turn can reduce transmission costs and help prevent supply interruptions caused by forced outages and power cutbacks.

Changes in the cost of building power plants in recent years have also prompted the construction of transmission lines and increased electricity sales among utilities. Between 1971 and 1978, for example, the cost of building coal-fired and nuclear power stations increased by 68% and 142%, respectively, in real (e.g. inflation-adjusted) dollars.[7] Partly as a result of increases in power plant construction costs, electricity costs across the nation rose an average of 175% between 1970 and 1980, with prices in many areas jumping by 250%.[8]

If long distance transmission capability exists, utilities with excess generating capacity in the form of older and generally cheaper power plants are able to offer relatively inexpensive electricity for sale to other utilities. For the utility with excess generation capacity, long distance power sales offer a source of income to offset fixed costs. Utilities purchasing power can reduce their operating expenses, avoid the construction of enormously expensive power plants and skirt the uncertainties about what the future holds for construction costs, pollution control requirements, and the emergence of new power generation technologies.

Changes in the cost of fuels, like shifts in power plant capital costs, have further helped to create regions of relatively low and high electricity prices throughout the country and to promote long distance power transmission. The prices of fuel oil and natural gas in particular have increased dramatically since 1973 relative to coal and uranium fuel, recent oil and gas price decreases notwithstanding, thereby adding to the cost of generating power at many existing plants. According to a study by the National Coal Council, the difference in the fuel price component of the cost of electricity generated in New Jersey and Pennsylvania was 8.6 cents/million BTUs of fuel input in 1965; by 1984 the differential was 78.8 cents/MMBtu. In 1965, fuel for electricity generated in California was slightly cheaper than fuel in neighboring Nevada; by 1984, Nevada fuel cost on the average 159.3 cents/MMBtu less than fuel in California.[9]

The National Coal Council further estimates that over 20 million tons of new coal production was being poured into power boilers in 1984, largely in the Midwest, to generate power to replace 85 million barrels of oil previously consumed at oil-fired units, frequently in the Northeast.[10] By way of example of this "oil-back-out", in New Jersey, oil consumption at six large power plants dropped from 12.2 million barrels in 1978 to just 3.6 million barrels in 1982.[11] To replace the power generated by this oil, New Jersey utility companies increasingly purchased electricity produced largely from coal-burning power plants located in other states. Power imports to New Jersey from grew from no imports in 1966 to over 50% of the state's total electricity demand in 1981.[12]

EHV transmission is an increasingly important factor shaping new power supply strategies as well as affecting generation and use patterns from existing power plants. Long distance transmission capability can, for example, encourage the construction of power plants in areas with low construction costs or fewer environmental restrictions. By sizing power plants to supply several utilities demand throughout a large region, such strategies can also take advantage of economies of scale in construction. Furthermore, as explained above, importing power from another region can delay or eliminate the need to build some power plants altogether.

Long distance interregional electricity transmission can also help define and mold national energy or environmental policies. For example, the reduction in use of oil-fired power plants in the Northeast during the past decade has reduced local air pollution levels. The increased reliance on electricity imported from the Midwest as a substitute source of power, however, could contribute to the formation of acid rain. One study has calculated that over 2.3 million tons of sulfur dioxide air pollution, some 13% of the utility industry's total SO2 pollution, resulted in 1984 from the generation of electricity bound for export to end users in power importing states.[13] Future acid rain control programs could affect the patterns of long distance electrical transmission and vice versa.

THE TRANSMISSION BOTTLENECK

Access to EHV transmission, therefore, is one of the keys to increased power sales among utilities which in turn frequently offers utilities an opportunity to decrease electricity costs, improve reliability in power delivery to end users, and attain a number of other attractive goals. A problem, however, is encountered wherever the existing EHV transmission system is inadequate to meet the demand for long distance transmission service and when obstacles are encountered to the construction of new transmission facilities. These conditions are frequently being encountered today.

Transmission capacity is increasingly being stretched to the limit in some regions of the country where growth in the transmission system has been unable to keep pace with sprouting interutility sales. According to a 1985 study by the North American Electric Reliability Council, existing transmission corridors between the Midwest and the East were loaded to 97% of capacity in 1983 and 1984, while capacity utilization in the Pacific Northwest ran 83% in 1983 and 92% in 1984.[14] Transmission line reserve margins could decrease further if the rate of power line construction declines as it has over the past two decades. About 29,000 miles of new transmission lines built between 1975 and 1984, compared to 34,000 miles which were constructed between 1965 and 1974. For the decade 1985-1994, only 15,000 miles are expected to be completed.[15] Many factors contribute to this decline in the pace of transmission line construction, including lower electrical demand forecasts and competing financial obligations of some utilities, but the impact eventually will be to constrain long distance power transmission capability.

Complicating the issue of increased demands for long distance transmission capacity are technical constraints on utilizing existing transmission lines. Historically, the design of transmission lines by a utility closely followed projected patterns of developing demand within the company's franchised service area. Utility specific "mini-grids" of low voltage power lines were adequate to assure the flow of electricity from any of a number of power plants to all locations within the utility's service area. The direction of power flow at any moment could depend on the particular generating plant then in operation. However, sustained unidirectional flows of high volumes of electricity can over stress these electrical grids leading to service cutbacks and forced outages.

Many organizations which have examined the adequacy of the nation's transmission systems in recent years have come to a conclusion that impediments to the expansion of EHV transmission lines threaten to undercut the long-term reliability of the electricity grid or could hamper the delivery of low-cost electricity via interutility sales. Four examples follow.

o The North American Electric Reliability Council observed in a 1985 study that "The transmission systems continue to be heavily loaded a high percentage of the time...Building more transmission lines would increase the capacity to transfer economy energy and, at the same time, increase the capability to respond to emergencies. However, there are impediments and disincentives to planning, licensing, and constructing new lines."[16]

o In 1986 the National Governor's Association created the Committee on Energy and Environment Task Force on Electricity Transmission because "While the Governors believe our transmission system is currently technologically adequate and reliable, they (the Governors) have expressed concern that it could be incapable of supporting an increased level of economical power transactions in regional and national markets."[17] That Task Force published a report in 1987, entitled Moving Power: Flexibility for the Future, which identified a number of impediments to power transfers.

o The National Regulatory Research Institute, the research arm of the National Association of Regulatory Utility Commissioners, took up the transmission issue in its September 1987 study, Non-technical Impediments to Power Transfers. The study noted that "There is general agreement among utilities, wholesale customers and others that (transmission line) siting and licensing problems are among the most significant barriers to expanded bulk power transfers."[18]

o Finally, the National Coal Council reviewed the EHV transmission system in this country in 1986 and

> concluded that "For the next decade, the addition of new EHV transmission will not be keeping pace with the anticipated growth in electrical demand...Impediments have been accumulating since the mid-1970s and, by now, are beginning to have a profound effect on the electric utility industry's ability to undertake new major transmission line construction."[19]

SITING PROCEDURES

Impediments to the siting of transmission lines generally arise as competing interests group interact within the context of the institutional and regulatory framework for power line siting. This section provides an overview of transmission line siting procedures starting with the long range energy planning process through which states and utilities strive to identify future electricity supply requirements. Once a need for new power supplies has been identified, specific transmission line projects are designed by utilities and approval for those projects is sought from state agencies charged with certification and licensing. Moreover, project approvals from a variety of local governmental entities are usually required. In addition to these state and local siting procedures, this section also discusses special siting requirements for power lines crossing federal and tribal lands and for multi-state transmission line projects.

Capacity Planning

Recognition of the need for new transmission lines usually surfaces through long range energy planning processes which attempt to predict electricity demand patterns in future years and decades. At least 31 states require electric utilities to file long range supply and demand plans for their service areas.[20] These plans discuss, among other issues, anticipated electricity supply and demand, the need for new power generation or transmission facilities, and the role expected to be played in the supply and demand picture by nonconventional or nonutility generated power. Moreover, utilities are required to submit planning analyses to support their applications for approval of specific power generation or transmission projects. Long range energy plans generally reflect a 20-year planning horizon, although shorter-range planning frameworks of 10 to 15 years are not uncommon.

In many cases, utility plans are supplemented by energy planning efforts made by state government agencies. A recent survey of state electricity regulatory programs analyzed by the West Virginia Public Service Commission (hereafter referred to as the West Virginia PSC survey) identified 15 states where public utility commissions performed independent electricity plans and 11 states where planning was performed by a state energy office or department.[21] However, laws in only a few states, such as California, New Jersey, and New York, require agencies to solicit public comment during the planning process and to publish state energy plans at periodic intervals.

Several factors undercut the effectiveness of energy planning processes in creating the technical rationale to support new long distance EHV transmission lines, especially if those lines connect different utility service areas in different states. First, many state energy regulatory agencies do not have adequate staff either to scrutinize utility long range plans or to prepare detailed energy forecasts on their own. Thus planning reports often receive close review by a state agency only in the context of a review of a specific construction project proposed years after the need for the project was first identified, but not critically studied at the time, in a long range plan.

Secondly, separate long range plans are normally submitted to regulatory agencies by individual utility companies and each plan discusses only the portions of energy projects directly affecting that utility, although the utilities themselves collaborate on joint project plans. Most state-mandated long range planning programs do not require utilities jointly involved in the development of a transmission line to coordinate their planning reports with regard to that project. The task of consolidating the individual plans into a comprehensive picture of a state's electricity system, eliminating overlap and filling in the blanks where necessary, often falls to the limited resources of the state agency to which the plans are submitted.

In the same vein, since utilities' plans tend to focus on supply and demand issues within their respective service areas, issues related to power purchases from other utilities, including the construction of transmission lines to facilitate interutility sales, are not necessarily addressed in detail in long range plans. Traditionally, the issue of the need for new power plants within a utility's service area is the central question addressed in long range planning and it overshadows transmission and interutility sales issues. Thus the National Governor's Association report noted that "...determinations of transmission requirements are frequently ancillary or iterative to, rather than integral to the determination of need for new generating capacity."[22] Identification of the overall efficiency or economic benefits potentially obtainable from expansion of the EHV transmission line system and increased interutility sales can easily go unrecognized in the planning process.

State Certification and Licensing

Major transmission line construction projects require some sort of state certification and/or licensing. Certification normally comes in the form of the issuance of a "Certificate of Public Convenience and Necessity" (CCN) by a state's public utility commission (PUC). Other state agencies, such as the environmental protection department, are also involved in the licensing of projects through, for example, their responsibility to issue requisite construction and operating permits. In some states, power project siting boards coordinate state agency responses to transmission line projects as well as serve as decisionmaking entities. A CCN is a prerequisite in many cases for other permits and authorizations, such as eminent domain power, which might be needed for the completion of the project.

From the perspective of the public utility commission staff reviewing a transmission line CCN application, three basic concerns are usually analyzed in detail. They are the demonstration of need for the project by the applying utility, the potential public benefits and costs of the project, and environmental and public health considerations. Of the three, the need for more transmission capability is generally the most significant issue.

Requirements for documentation in support of a CCN application are vague in most states, which creates one of the many sources of uncertainty in the certification process. Applications usually include formal testimony by the utility summarizing the utility's argument for the project. Upon receipt of an application, a case or docket is opened by the PUC, a hearing schedule is established and potential interveners are notified. Interveners frequently include other state agencies and utilities, large power users, and public interest groups.

The PUC either accepts or rejects interveners' applications and the case usually enters a "discovery" phase during which the various parties collect and study information about the project obtained through depos~~itions~~ and other methods of information exchange.

At the conclusion of the discovery phase, the PUC staff and the interveners file their formal testimony, including the testimony of expert witnesses, and the utility files a second, or rebuttal, testimony. The case next enters the hearing phase during which the presenters of testimony submit to examination and cross examination by attorneys for all parties. Hearings are frequently adjudicated by a hearing examiner appointed by the PUC commissioners, although they are sometimes held in front of the commissioners themselves. Most states also require that public meetings be held to solicit public opinion on the project. In some other states public meetings can be called at the discretion of the public service commission.[23]

In instances where a hearing examiner is utilized, he or she prepares a report and a proposed or recommended decision which is reviewed and upheld, rejected or modified by the PUC commissioners. If the commissioners hear the case, they prepare both the report and render the final judgement. PUC decisions are usually appealable to the state court system.

The West Virginia PSC survey found that the certification process in most states generally takes less than a year, although the process can take years in some cases (see for example the Washington Loop Project case study below). In none of the states responding to the survey is a limit placed on the amount of time a public service commission can take to decide on a CCN application.[24]

Depending on the state, a utility can proceed to obtain permits from other state agencies needed to construct a transmission line either before, during or after a CCN is granted. In 11 of 33 states responding to the West Virginia PSC survey, utilities are not permitted to pursue required permits from other state agencies until a final ruling on a CCN has been rendered.[25] In at least 18 states a joint certification and siting approval process has been instituted which can simplify and expedite state agency permitting issuance. At least 14 states have established some sort of a siting board to coordinate and resolve permitting issues.[26]

Even with all required state agency permits in hand, a transmission line can not be constructed until rights-of-way have been acquired for the land through which the line travels. For some projects, land acquisition for the transmission line corridor can not be obtained voluntarily by the utility through negotiation with the land owner. Such opposition can result in the abandonment of a project or a costly rerouting unless the utility can exert a power of eminent domain to acquire the needed property upon payment of a court-approved level of compensation.

In a few states, utilities are granted the power of eminent domain by state law for any transmission line project, but in most the issuance of a CCN is a prerequisite before eminent domain powers can be exercised. According to the West Virginia PSC survey, in at least 11 states the issue of whether not eminent domain powers are granted to a utility is decided as one component of the certification and siting process. At least 17 states require a separate application and decisionmaking process for eminent domain which occurs after siting approval has been obtained.[27] In some states, the power of eminent domain is obtained from a court which considers issuance of a CCN and siting approval as evidence in its decisionmaking process.[28]

Local Permits and Approvals

Special use permits and zoning variances issued by local and county governments are commonly required before construction of a transmission line project can begin. Acquisition of local permits can be an extremely complex and time-consuming undertaking, especially in areas where significant local opposition to a transmission line project exists. A recent case study by the National Coal Council of a 50 mile transmission line project found that over 30 local and county governments had to be individually contacted regarding the project.[29] For a long distance interstate transmission line project, separate approvals from literally hundreds of local government entities can be required. Each decisionmaking process generally includes an appeal process through the court system in addition to the administrative review process.

Several states grant, as part of their certification and licensing processes, the authority of one agency to override the decisions of other agencies, including local governments. At least 17 states grant such powers,[30] but in at least 12 states, local agencies have the authority to block transmission line projects from being built within their jurisdiction.[31]

Permitting Transmission Lines Across Federal Lands

Long distance transmission lines frequently cross lands administered by federal agencies, especially in the western United States. In most cases, siting a line on federal lands requires a right-of-way from the administering agency in a process separate and distinct from state and local agency actions. Federal land permitting frequently involves three steps; an environmental review, a land use planning process, and a review of a specific right-of-way application.

Under Section 102(2)(c) the National Environmental Policy Act of 1969 (NEPA), an Environmental Impact Statement (EIS) must be prepared prior to any major federal action significantly affecting the quality of the human environment. Most major transmission line projects that cross long stretches of federal lands fall under the EIS requirement.

The EIS process begins with a preliminary analysis which is aimed at determining how extensive an environmental review is required by NEPA for a particular project. A "finding of no significant impact" can permit a project approval process to continue without more analysis under NEPA. If minor impacts are anticipated, an abbreviated environmental assessment is deemed adequate.

For projects with significant potential impacts, a full EIS is required to be prepared by the agency administering the land affected by the transmission line. In cases where multiple categories of federal lands are involved, a lead agency is selected, but all agencies participate in and are bound by the results of the EIS. For example, for the 1984 EIS analyzing the 345 KV line between the San Juan Generating Station in New Mexico and Rifle, Colorado, the Rural Electrification Administration acted as the lead agency and the Forest Service (USFS), the Bureau of Land Management (BLM) and the Western Area Power Administration served as cooperating agencies.[32]

The first step in the EIS process is a "scoping" effort during which important environmental issues raised by a proposed project are identified, in part through a solicitation of public opinion. This is followed by the actual environmental analysis process. Under NEPA, alternatives to the proposed process must also be identified and studied, including a "no-action" alternative of not proceeding with the project in any form. This stage of the process concludes with the publication of a Draft EIS which is followed by a public comment period. The comments are reviewed, revisions to the draft are made, and a Final EIS is published, which includes responses to public comments. The agency preparing the EIS then issues a Notice of Decision endorsing one or more of the project alternatives discussed in the EIS as the "proposed" or "preferred" option. EIS's and Notices of Decision can be appealed first to the Director of the lead agency and then to the federal court system, starting with a U.S. District Court.

Separate from the NEPA process, several federal agencies, notably the Bureau of Land Management and the U.S. Forest Service are required to perform comprehensive land use plans for the lands under their jurisdiction and to identify areas suitable for the construction of transmission lines. Land use plans, called Resource Management Plans, for public domain lands under control of the BLM are required under the Federal Land Policy and Management Act of 1976. Similarly, National Forest land use plans are required under the National Forest Management Act of

1976. Utility corridors are frequently discussed in Regional Guides, which are prepared for each of the USFS's ten regions, and in the Land and Resource Management Plans for each National Forest. Identification of potential utility line corridors is an important part of these land use plans because only projects sited along corridors identified as suitable for transmission lines in the plans can be approved.

Many land use plans, such as the recently released Farmington Resource Management Plan for the BLM administered lands in the San Juan Basin in New Mexico, employ a "window" approach to planning for transmission lines which seeks to identify general areas where power lines might be needed and more specific areas where a conflicting land use would preempt transmission line construction. This approach provides significantly more flexibility in later line siting efforts than would exist if only specific corridor paths were approved at the land use planning stage.

Apart from the NEPA and land use planning processes, approval of the use of federal lands for a specific transmission line is still required from the administering federal agency. Depending on the type of transmission line project and the categories of federal lands involved, a number of federal agency permits might be required. For example, the BLM issues a Right-Of-Way permit across public lands and the USFS issues an

Authorizing Document for a line to cross a National Forest. For lines crossing an international boundary, a permit must be obtained from the Department of Energy as the implementing agency of a 1953 Presidential Executive Order affecting international electricity transactions. The Department of Defense can deny a permit if it interferes with a major military installation or if it is deemed to interfere with national security. The Federal Highway Administration must approve corridor paths along interstate highways, which is currently only done as an exception to FHA policy. Corps of Engineer permits must be obtained for lines crossing interstate navigable waterways. The Federal Energy Regulatory Commission must approve transmission line projects associated with federal hydroelectric facilities.[33]

Permitting Transmission Lines Across Tribal Lands

Approval of transmission line corridors across tribal lands must be obtained from the governing Tribal Council or other tribal ruling body for the affected lands. There is no federal requirement for land use planning on tribal lands, nor are there standardized procedures for applying for a right-of-way across tribal lands. Reporting requirements and the decisionmaking process employed to rule on the application vary among different tribal governments and can change markedly over time.

Utility companies cannot exercise the power of eminent domain on tribal lands regardless of whatever approvals of transmission line projects have been made by federal or state agencies. In eight states, tribal governments are consulted as part of the state process for transmission line certification and licensing even if tribal lands are not involved.[34]

Siting of transmission line on tribal lands has proven to be very difficult in some instances, even when only sparsely populated lands are involved. For example, proposed transmission line rights-of-way from the San Juan power plant in New Mexico across the Navajo Nation where the transmission system can be linked to the electricity demand centers in the Far West have been debated by the Navajo Tribal Council literally for decades and remain a very controversial topic with no clear resolution in site.

Regardless of the decisionmaking procedure used by the tribal government, any action taken by a tribal government must also be approved by the U.S. Bureau of Indian Affairs (BIA), as the federal trustee for tribal lands. Because BIA approval of a permit for a large transmission line project is often ruled to be a major federal action under NEPA, Environment Impact Statements can be required for projects on tribal lands. For example, the BIA has acted as lead agency for the EIS for the proposed Ole power line in New Mexico because several proposed routes could affect Pueblo Indian lands or sacred sites within a National Forest (see Ole Project case study below).

Multi-state Siting Efforts

Certification and siting of transmission lines is generally the responsibility of the state regulatory agencies which have jurisdiction over the utilities proposing the project or the land traversed by the power line. For a long distance power line across several states, regulatory agencies in each state independently consider the portion of the project within their jurisdiction. Denial of a CCN in any one state can lead to the abandonment of an entire interstate project.

An interstate transmission line project which distributes costs and benefits in many states presents a difficult problem for state regulatory agencies as they assess the overall need for the project in relation to the traditional state-specific criteria for certification. Only a few programs have been undertaken to date to bring regulatory agencies together during the planning or permitting of an interstate power line. Communication among states most frequently occurs on an informal basis through associations of state agencies such as the National Association of Regulatory Utility Commissioners (NARUC). Other examples include: the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, which in 1987 established a joint Committee on Regional Electric Power Cooperation; the National Governors Association, which has formed a Committee on Energy and Environment Task Force on Electricity

Transmission; and the New England Governors' Conference, which has formed an interstate agency Power Planning Committee. Occasionally regulators from other states will be invited to observe or participate in a planning or certification process taking place in another state. Sometimes a state agency will take the initiative to intervene in a regulatory proceeding in another state.

The federal government currently plays only a small role in transmission line certification issues for interstate or interutility projects. Under the Federal Power Act, the Federal Energy Regulatory Commission (FERC) has the authority to set the wholesale rates which utilities may charge for bulk or economy sales. Although FERC decisions are critical in determining the overall economic viability of a long distance power line project, the agency itself does little to assist in power line siting.

Utility companies themselves have done the most to foster interutility planning for reliability purposes, including the identification of the need for new long distance transmission capacity. One agency that performs this function as part of its mandate is the North American Electric Reliability Council. The Council and its nine regional constituent councils were created to promote reliability in electricity supply. In pursuit of this objective it often undertakes studies of methods to facilitate interutility power sales.

Power pools of utility companies, of which about 30 currently exist in the United States, provide another forum for joint utility planning and transmission line project development. The New England Power Pool and the Pennsylvania-Jersey-Maryland Power Pool are examples of such organizations of utility companies. Some large utility holding companies, such as the American Electric Power Corporation, prepare a single long range electricity plan for all of its subsidiary utility companies. Moreover, ad hoc interutility agreements occur frequently among utility companies. For example, the Mid-American Interconnected Network (MAIN) agreement establishes "Transmission Loading Relief Procedures" to set power delivery schedules if overloading of a transmission line occurs in one utility's service area as a result of a sales transfer between two other utilities.[35]

With one exception, multi-state utility and state agency programs regarding long distance transactions are voluntary. The one mandated interstate electricity planning agency - the Northwest Power Planning Council (NPPC) - has been established and is guided by federal legislation.[36] Washington, Oregon, Idaho and Montana are the member states of NPPC, which was created by the Pacific Northwest Electric Power and Conservation Act of 1980. The Council prepares long range electricity demand forecasts for the region and develops power supply plans capable of meeting that demand.[37]

IMPEDIMENTS TO TRANSMISSION LINE SITING

Institutional, regulatory, and legal elements of the process for siting transmission lines, from long range capacity planning through the exercise of eminent domain and construction, can delay EHV power line projects by adding to their completion time and cost and by contributing to the uncertainty that the required approvals will be obtained. Three sources of impediments are discussed in this section; power line approval procedures, jurisdictional complexities among agencies required to give approval to a project, and the lack of multi-state coordination.

Obstacles to Transmission Line Approval

Approval for a transmission line project in one sense begins with the long range planning process years before an application for a specific project is filed. State-mandated planning processes tend to have a strong focus on the need for new power plants and frequently do not analyze in depth the potential for increased long distance interutility transmission to facilitate interutility sales as a supply option. The inherent uncertainties involved in interutility power sales, especially from another state or from Canada, often result in a low ranking of this option in long range plans, and hence little discussion of interutility sales among supply alternatives in planning documents. Other shortcomings of the long range planning process are that plans are usually required for individual utilities even though some transmission line projects are jointly sponsored, they are not required to discuss components of projects owned by other utilities or located out of state, and they are reviewed by a state agency staff that does not necessarily have the in-house expertise or resources to thoroughly scrutinize them. The same shortcomings often apply to long range electricity plans produced directly by state regulatory agencies.

The lack of attention given to long distance transmission projects and interutility sales during the long range planning process stands in sharp contrast to the attention the issue draws in the world of actual electricity sales contracts and transmission line project development. Yet, when the time comes for decisions about specific projects and contracts, limited analysis of the complex issues involved is available from past planning efforts.

State laws regarding the obligations of utilities and utility regulators alike often create obstacles to long distance transmission line projects. State utility franchise laws generally place the highest obligation on a utility to provide reliable service within its service area. This provides a disincentive for a utility to consider a project such as building a power plant or transmission line which may have as its goal supplying electricity to customers of another utility. This argument has been summarized by the National Regulatory Research Institute as follows:

> "The franchise system, on the other hand, may be a major problem because it is an expression of the natural monopoly concept. Among other things, in return for an exclusive service territory, the latter means the utility must provide all comers with service at all times. It will, therefore, attempt to size its system to meet its expected demand, and will strive to be self-sufficient in terms of supply in order to assure its ability to provide service....At the same time, the utility is legally forbidden to look for new customers outside its area. As a result, under normal circumstances, it will generally have minimal need for purchased capacity, and will have little available to sell to others."[38]

State regulatory agency transmission line siting criteria reflect the same specificity with regard to service areas that guide most utility company actions. In assessing need for a transmission line, state public service commissions generally look first to the benefits to the customers of the utility proposing to build the line. These benefits are then balanced against the anticipated costs of the project, including impacts on the environment, the lifestyles of affected residents and other public interest considerations.

A difficult analytical dilemma is frequently encountered by state regulatory agencies facing an application for a long distance transmission line project. Often the only direct benefit to the customers living in the service area through which a transmission line passes is improved reliability of electricity supply, which is impossible to quantify. The quantifiable benefits of low cost electricity often accrue to customers living in other service areas or states outside of the agencies jurisdiction or the scope of the application. On the other hand, the local costs are readily obvious and in many cases quantifiable, including exposure of people to high voltage electrical fields, lifestyle and economic disruption, and aesthetic, environmental, and recreational impacts.

This situation complicates the balancing process for state regulatory agencies, especially in states, such as Wisconsin, which have laws which require that local or statewide benefits outweigh local costs as a condition of power line approval.[39] Many state regulatory agencies have responded by developing conservative "prudency" or "public interest" criteria against which to judge the merits of utility projects under review which have on occasion been criticized as "highly parochial attitudes" that dampen the enthusiasm for utilities to undertake long distance transmission line projects.[40]

Another problem utility company applicants face is that power line approval criteria can differ among agencies especially when agencies are located in different states. As a result, power companies often must file multiple applications in support of a transmission line project. Moreover, the information in each application must tailor fit the evaluation criteria of the agency to which it is submitted.

Unless one agency is empowered to veto a contrary decision by another agency, a utility applicant faces several "show-stopper" regulatory review processes. An adverse decision in any one arena in any state can force the abandonment of the entire project. Moreover, criteria used by a single agency can change, even during the process of review of one project. As noted by the National Coal Council:

> "a strong endorsement of a major power supply project by a regulatory commission at one point in time does not provide any real assurance that the same regulatory commission (with, perhaps, a different membership) would not oppose the continuation and completion of that very project at a later point in time."[41]

A final consideration is that very few siting procedures contain any deadlines for decisionmaking. Thus, it becomes impossible to predict with confidence when a power line project approval or denial will be forthcoming. This too adds to the uncertainty underpinning long distance transmission line projects which require approval from dozens of agencies. Even when deadlines are established, they usually affect only a component of the decisionmaking process, not the entire process. For example, schedules set for regulatory agency actions are completely distinct from the schedules set by courts to which judicial challenges to those actions are addressed. Scheduling problems encountered by transmission line projects have led the National Governors Association (NGA) to conclude that "the lack of a definitive time table for the regulatory process appears to be one of the biggest causes for delay."[42]

Jurisdictional Complexities

A labyrinth of regulatory agency requirements face the sponsors of long distance transmission line projects, involving federal, state, and local agencies and courts. Coordination among agencies is frequently poor and jurisdictional boundaries are often vague, leading sometimes to mismatches, overlaps, and gaps in agency responsibilities and to interagency conflicts.

Federal and tribal land administering agencies have permitting powers which exist separate from state regulatory agency approval procedures. Decisions by these agencies bear on the viability of a transmission line project regardless of state agency actions. Federal and state jurisdictions mesh somewhat more closely between the Federal Electric Regulatory Commission (FERC), which sets wholesale power rates upon which interutility sales depend, and state public utility commissions, which usually grant required project licenses. However, according to the National Regulatory Research Institute, "there is virtually no coordination between the two entities in regard to these activities."[43]

Depending on the state, a number of state regulatory agencies are involved in the permitting process for a large transmission line project. Although many states have established either a Siting Board or appointed a lead agency to coordinate the state review process, guiding an application through the regulatory apparatus can be a difficult and time consuming task. Joint agency permitting processes remain the exception, not the rule, and because consideration of some permits is often contingent on issuance of others, agency approvals must sometimes be sought sequentially rather than simultaneously.

Participation of a multitude of local municipalities and county governments in permitting a long distance transmission line represents another layer of jurisdictional complexity. Even in states where local decisions can be overruled by a state siting agency, local government actions are still important to the overall siting process especially where strong local opposition makes a state agency leery of vetoing local government actions.

Added to this intricate network of regulatory agency interactions is the court system. Judicial review of regulatory agency actions is a legal right of opponents to most agency decisions. Thus, depending on the agency and the decision involved, federal, state, and local courts frequently enter the transmission line approval process and can create lengthy tangents from the regulatory agency review process.

Lack of Multi-state Coordination

Variations in transmission line approval processes among states coupled with the lack of coordination in decisionmaking and interstate information exchange can create major obstacles to long distance power line projects. As noted by the National Governors Association:

> "differences in both state siting and certification procedures and in the regulatory process itself may frustrate efforts to develop multi-state lines even when those lines would be acceptable to each of the states involved."[44]

Even where there is some fledgling effort at inter-state coordination, no one state agency is necessarily bound to implement a decision made as a result of multi-state planning effort.

Coordination between state agencies and the FERC is also incomplete. The current practice of independent actions by FERC and by state regulatory agencies has moved the National Regulatory Research Institute to conclude that "the federal-state regulatory dichotomy can be considered to be an important institutional impediment to the movement of bulk power between utilities."[45]

One problem that can result from the lack of coordination between FERC and state agencies is that state public utility commissions, as they make their cost/benefit analyses, cannot necessarily obtain from FERC information they need about whether interutility sales from a long distance transmission line will be economical and provide system wide benefits. Another potential problem is that state regulatory decisions with regard to interutility power projects can be affected by future FERC rulings which the agencies cannot anticipate and over which they have no control.

INTEREST GROUP PERSPECTIVES

A number of interest groups frequently interact during the siting of a transmission line. Although the positions of these groups are molded by the individual circumstances surrounding each project, a number of perspectives are commonly associated with each group. It is the clash between these perspectives during the siting process which frequently leads to the conflicts that impede transmission line siting.

Utility Companies

Utilities have moved a long way from the entrenched, adversarial approach they frequently took in the past to transmission line siting epitomized by the slogan "decide, announce, and defend". At least 35 utilities in the United States now have formal public participation programs to assist in the planning of utility projects.[46] Nearly all utilities include public participation at some point in their decisionmaking processes regarding transmission lines.

Nonetheless, it is common for utility companies to feel that criticism of transmission line projects comes from amateurs who cannot possibly understand the economic and technical intricacies of the electric utility industry. In many respects, utilities do know more, if not best, and in adversarial environments resentment can build as other interest groups "try to tell us how to do our business." Moreover, state franchise laws and historical utility standard operating practices tend to promote conservative, risk-averse attitudes on the part of many utility companies which on occasion can reinforce a skepticism towards suggestions originating outside utility company circles, especially ideas regarding complex projects such as interstate transmission line construction.

Government Regulators

State and federal government regulatory agencies respond first and foremost to the statutory mandates under which they operate. For state public utility commissions this usually means careful implementation of prudency and cost/benefit balancing concepts in transmission line siting reviews. For an environmental protection department this translates to assurance that transmission line applicants will comply with a wide range of construction and operating requirements.

A narrow perspective can frequently develop among individual regulatory agencies with each agency focussed on fulfilling its mandated responsibilities. This approach does not necessarily foster free information exchange, cooperation, and compromise of decisionmaking authority and it can undercut the development of a rationale for collaboration among agencies that could be needed to expedite and facilitate transmission line siting approval.

Landowners and Affected Populations

People who live, work, or play directly under or near a proposed transmission line corridor are frequently the most vocal interest group during the siting process. Their concerns can take many forms. If they live directly beneath the proposed path of the power line, they might be opposed to moving or they might fear that they will be inadequately compensated for the loss of their homes. These same concerns are typical if businesses, such as farm or ranch operations, are situated along a line's path. Public health concerns are also commonly encountered among people who will be exposed to the electrical field generated by an EHV transmission line.

Local opposition to a transmission line can also result if the line is perceived to threaten non-economic values attached to the land. Thus, for example, A some Native American groups have opposed transmission lines crossing lands they hold sacred. Subtle lifestyle disruptions caused by transmission lines, such as aesthetic degradations, can foster controversy about a project. Non-economic concerns can cause an affected population to view as unfair the distribution of the economic costs and benefits of a transmission line project if they believe they will absorb a disproportionate share of the costs while the benefits are more widely dispersed or accrue to others altogether.

These concerns can often be addressed through careful route selection for a proposed line, extensive impact mitigation programs, and increased compensation to the affected population. Nevertheless, the perspective of the locally population can solidify into nonnegotiable opposition, typified by the slogan "not in my backyard."

Ratepayer Consumer Groups

The electricity ratepayer is usually concerned chiefly with the cost of electricity at the point of end use and, to a lesser extent, with long-term reliability of supply. Under the current conditions of excess power generation capacity in many parts of the country, these concerns frequently are reflected in support of increased competition in the electric utility industry, more interutility sales, and wider interutility connections to facilitate long distance transfer of cheap electricity. In some instances, however, concern over the cost of a transmission line project or over the future availability, cost, and reliability of supply can outweigh these pro-transmission expansion sentiments, leading some ratepayer organizations to oppose such projects.

Environmental Organizations

Environmental groups often take strong exception to the potentially adverse impacts of long distance transmission lines on the visual and physical environment, on wildlife, and on human health and traditional lifestyles. In many instances where proposed transmission lines cross inhabited areas, the concerns of environmental groups reflect those of local landowners, particularly with regard to public health issues and the disruption of traditional lifestyles and sacred sites.

Alternatively, environmental groups can oppose transmission line project because they conflict with land use objectives distinct from those held by the affected population, thereby placing them in conflict with the landowners on these issues. For example, a proposed corridor for a transmission line might appear to environmental groups to be a poor choice of use of the land compared to competing uses as wilderness, a plant or wildlife preserve, a habitat protection zone, or as a recreation spot. This situation often occurs for transmission line projects proposed to cross sparsely populated lands such as National Forests and other public lands managed by the federal government. Rerouting and impact mitigation measures can sometimes, but not always resolve satisfactorily many of these environmental concerns.

Energy Systems Advocates

A number of organizations have as their objective the promotion of a particular energy policy objective or technology. For example, "soft path" energy advocates believe that a combination of energy programs to promote conservation and decentralized power supply systems provide the best approach to long-term energy security in this country.[47] Similarly, trade organizations exist to promote individual energy technologies including decentralized systems, conservation, and "hard path" coal and nuclear generating technologies.

In some instances promotion of long distance electricity transmission and interutility power sales can be seen as antithetical to the objectives of these organizations and they have participated in the decisionmaking process for specific transmission line projects. For example projects involving sales of electricity from large fossil-fuel or nuclear generating stations, which are not the preferred power supplier among either soft energy proponents or decentralized power technology supporters, have drawn opposition from energy technology advocates. Thus, in the late 1970s, the California organization Citizens for a Better Environment opposed the expansion of long distance transmission capacity to that state from the Northwest in part because of concern that the capacity would be used as a justification for the building of several large nuclear power plants then proposed for construction in Washington state and opposed by the group on technology grounds.

On the other hand, in late 1987, the National Coal Association intervened in a Department of Energy proceeding in opposition to a permit to build a transmission line from Quebec, Canada to an existing utility line owned by Central Maine Power Company. The Association feared the project would promote the importation and use of hydroelectric power to the detriment of electricity produced at domestic coal-fired power plants.[48]

OPTIONS TO IMPROVE TRANSMISSION LINE SITING

According to the West Virginia PSC survey, state regulatory agencies have approved 515 transmission line projects of all types within the last ten years, while denying approval for only 18. More than two-thirds of the projects approved during the last five years have been completed.[49] Thus, the approval of transmission line projects by regulatory agencies is a routine, although difficult procedure.

The success rate of power line siting not withstanding, impediments to siting continue to draw fire from interest groups and a number of recommendations for ways to improve the siting process now enjoy considerable support in some circles. Several proposed recommendations are presented as policy options in this section.

Expanding the Planning Process

Inadequacies in the long range planning process affecting electricity supply and demand, especially with regard to transmission line planning, could be reduced in a number of ways. Simply providing more resources to the agencies involved in planning could help produce more comprehensive and insightful plans. Transmission line and interutility power sales issues could receive a higher priority in the planning process. The scope of planning efforts, including those submitted by individual utility companies, could be broadened to include regional and interstate electricity issues. Some entities which are frequently exempted from planning requirements, such as municipal-owned utilities and power cooperatives, could be required to participate more in planning.

Greater integration of planning efforts and transmission line project development could also enhance the usefulness of planning. More relevant and accurate long range electricity plans should be of greater usefulness during the regulatory review process of specific transmission line projects, especially with regard to the overall costs and benefits of a project. As noted by the National Governors Association, "planning on a multi-state or regional basis can help identify even larger sources of savings from improved coordination of generation and transmission capacity development."[50]

The Washington Utilities and Transportation Commission has been developing a new long range planning process since mid-1987 which is designed to implement several of these recommendations. Called the Least-cost Planning and Avoided Cost project, the Commission is developing a standardized computer model using a spreadsheet format to record and analyze economic data on future electricity supply and demand. Consistent reporting requirements are being developed for each utility company required to submit long range electricity plans. The Commission hopes to merge the utility plans and to create a statewide energy resource blueprint. The immediate objectives of the program are to improve the organization of utility-supplied data, to better predict and understand the implications of future electricity supply and demand patterns on the state, and to enhance the Commission's ability to analyze proposed power projects.[51]

Improved planning should help utilities anticipate land requirements for transmission line corridors farther in advance and with greater certainty of actual future need. This has led the National Governor's Association and others to suggest that several transmission line corridors be pre-approved as part of the planning process. Creation of "resource banks" of approved corridors could provide "a bridge between the planning and transmission line certification processes to reduce the lead time for final approval" of transmission line projects, the NGA believes.[52] On the other hand, it can be argued that preselection of multiple corridors, some of which will never be used for transmission lines, can needlessly involve and upset people, lead to unnecessary changes in patterns of land use and value, and add significantly to the cost of planning.[53]

Streamlining the Regulatory Approval Process

Simplifying and shortening the process for obtaining certification and license approvals for a transmission line project from state and local regulatory agencies has undoubtedly been the single largest target of reformers of the siting process for years. Frustration with the difficulties inherent in the current system has in part prompted the Electric Power Research Institute to develop a handbook for utilities to use as it weaves through the regulatory labyrinth, entitled optimistically A Streamlined Procedure for Obtaining Regulatory Approval for New Transmission Lines.[54]

One of the most frequently enunciated suggestions is that the siting process in a state be coordinated by a single agency or by a Siting Board composed of members of several agencies. This step has already been taken in about 12 states, although the circumstances when the Boards become involved and with what powers varies considerably.[55] This move toward "one-stop" shopping for licenses and permits has in fact expedited the siting process in many cases, but, as the Coal Creek Project case study presented below shows, it provides no guarantee that controversy surrounding a transmission line project can be resolved. Nonetheless, the National Governors Association has concluded that "consolidation of the approval process within a single agency (even if that agency must work with other agencies) appears to improve the predictability and certainty of the regulatory process, and may increase the speed with which the state acts on project proposals."[56]

Endowing siting agencies or boards with the power to overrule decisions made by other regulatory agencies and local governments is another suggestion commonly offered to speed government review of transmission line project applications. Many state programs currently do authorize preemption of decisionmaking authority by some agencies, and this has resulted in some instances in faster siting of transmission lines. But delays can still occur in part because of a reluctance to assert veto authority and in part because it is the decision of another agency that can be preempted and not the right of that agency to conduct its review process. Thus, endowing an agency with veto power may save little time and effort in the review process, but it does create a greater degree of certainty over the final outcome.

Establishment of clear criteria against which a transmission line application can be measured could also help simplify the siting process. Some states, including Florida and Montana, have established specific siting criteria, such as minimum corridor widths for power lines, based on generic issues, such as public health concerns. Greater definitiveness and specificity in siting criteria can ease the information requirements for the applying utilities and help focus the review process.

Finally, many critics of transmission line siting procedures call for the institution of firm deadlines in decisionmaking. The NGA has noted that "of those (impediments) involving state regulation, lack of a definitive time table for the regulatory process appears to be one of the biggest causes of delay."[57] On the other hand, the price tag for forcing decisions within tight schedules can be inadequate review and analysis of the issues involved. Moreover, structuring a penalty for an agency for missing a deadline poses difficulties and, as a result, deadline schemes usually act more to pressure rather than coerce agencies to act on utility applications for transmission line projects.

Involvement of Multi-state, Federal, or Independent Agencies

A final group of policy options are tailored especially for application in the siting of long distance transmission lines which involve several states.

The National Coal Council has been particularly outspoken in calling for increased federal government involvement in siting power lines. The group has written to the Department of Energy that "The Secretary of Energy should declare that it is in the national interest to have in place -- and to reinforce as the need arises -- strong interstate electric transmission networks." According to the Council, the Secretary "should intervene or otherwise appear before state and local regulatory bodies that are considering the construction or siting of transmission lines that have interstate or regional implications."[58]

Increasing the powers of the Federal Energy Regulatory Commission could provide another method of bolstering the federal role in interstate transmission line siting. In this regard, the Coal Council has urged the Department of Energy to support FERC "in its efforts to resist state encroachment upon its jurisdiction over the interstate transmission of electrical energy."[59] FERC or another federal agency could affect siting indirectly by creating "model" siting procedures or transmission line application review criteria which could help standardize procedures used by state regulatory agencies.

Expanding the concept behind the congressionally established Northwest Power Planning Council to other regions could offer another avenue to increase federal and multi-state involvement in transmission line siting. Alternatively, congressionally-approved siting "compacts" of states through which a transmission line is proposed to pass could create ad hoc multi-state decisionmaking bodies with broad siting powers.

Informal federal-state transmission line siting dispute resolution boards could provide forums where clashing interest groups can come to discuss and possibly resolve their differences. More dramatically, some have suggested that the federal government or some independent dispute resolution organization, such as the American Arbitration Society, could be empowered to make decisions on issues about which regulatory agencies in different states disagreed.[60]

Enhanced Public Participation

Most utilities and state and federal regulatory agencies have established extensive public participation programs which include participation in the review of transmission line projects. These programs seek to provide early disclosure of information and to solicit public input into the designing of utility projects. Citizen review, evaluation, advisory, and participation committees are commonly formed to help shape transmission line projects. Moreover, individual interest groups can make their opinions known through public comments, formal interventions, and legal appeal processes which occur at a number of points under most siting procedures.

Development of new models for public participation specifically geared to the circumstances commonly encountered during transmission line siting is an ongoing process which, if effective, could alleviate some impediments to siting. Toward that goal, the Edison Electric Institute convened a Task Force of public participation in 1982 entitled "Workshop on Utility Experience with Advanced Public Participation in Planning" and subsequently sponsored the preparation of a lengthy study of the issue entitled Public Involvement in Energy Facility Planning: The Electric Utility Experience. This 451 page book offers a collection of professional papers that its introduction claims "stands as the most comprehensive work to date on how the open planning process has functioned under the auspices of electric companies."[61]

THREE CASE STUDIES

The following three case studies illustrate transmission line projects which have experienced significant opposition. They offer examples of how impediments to transmission line projects surface in real situations and are resolved or, in some cases, not resolved. The case studies include examples of "innovative" as well as traditional power line approval mechanisms, thereby providing indications of how well some proposed "solutions" to power line siting bottlenecks actually work.

In each case, interest groups have exerted their influence at different stages in the decisionmaking process to impede or delay the project or to necessitate a substantial modification to the project design. In these three projects opponents of transmission line construction have concentrated their efforts at the state, federal, and local levels for approving power line construction, respectively. Opposition to the Coal Creek Project in Wisconsin focussed on the state siting process. In the case of the Ole Project in New Mexico, the federal environmental review process has already taken four years with no end in sight. Finally, controversy surrounding the Washington DC loop has been most vocal effectively expressed by way of the county court system.

The Coal Creek Project

The major components of the Coal Creek project include a 1,015 Mw coal-fired power station in North Dakota owned by two Minnesota utilities and a 436 mile, 400 KV direct current EHV transmission line connecting the plant with two shorter 345 EHV KV and one 115 KV alternating current line within the utilities' service areas (see map). The utilities involved are the United Power Association (UPA) and the Cooperative Power Association (CPA), both generation and transmission cooperatives serving a total of 33 distribution members.[62]

The Coal Creek project began in 1972 when the utilities agreed to work together on a power plant and transmission line feasibility study and an application to the Rural Electrification Administration for financing. A federal Environmental Impact Statement was completed in 1974 and preliminary approval was granted for the financing. Although state agency regulatory approval for the power plant and for a portion of the transmission line was obtained in North Dakota, significant

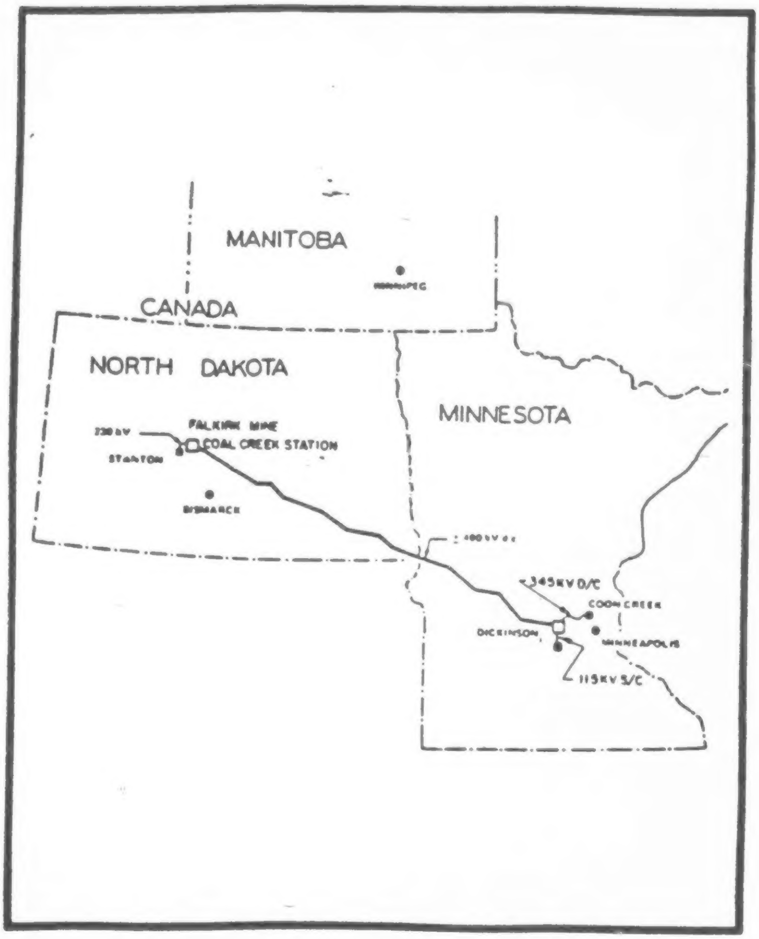

MANITOBA
WINNIPEG
CANADA
NORTH DAKOTA
MINNESOTA
230 kV
FALKIRK MINE
COAL CREEK STATION
STANTON
BISMARCK
±400 kV dc
345 KV D/C
COON CREEK
DICKINSON
MINNEAPOLIS
115 KV S/C

Figure 9.1 Major features of the Coal Creek Project

opposition to the project began to gel in Minnesota.

The major issues of contention were the economic and land use impacts of the power line on the prime agricultural areas through which it was to traverse and the potential threat to public health posed by the electrical field created by the line. The Coal Creek Project exemplifies the dilemma faced in the siting of long distance transmission lines of distributing fairly the project's total anticipated costs and benefits. Urban residents in Minnesota would benefit from the reliable source of low-cost electricity made available by the project. However, lifestyle impacts, notably perceived public health threats and interference with the agricultural economy, would be borne by a relatively small group of people living near the line itself who stood to gain little from the project. Although numerous actions were taken to balance the benefits, including condemnation payments which averaged $52,400 per mile for a 160 foot wide right of way, a consensus among interest groups was never achieved.

Ironically, the lengthy and bitter controversy unfolded in one of the first states to establish a "lead agency" siting approval process with the expressed purpose of speeding transmission line projects while facilitating constructive public participation. The Coal Creek Project was the first transmission line project to be brought before the Minnesota Environmental

Quality Board (EQB), the lead agency named in the 1973 Power Plant Siting Act. The multi-stage review process involved active participation by citizen evaluation committees, the public at large, the utilities, and other state agencies. By law, a decision by the EQB overrides any contrary action by another state agency and local or county governments.

The first step began in April 1975 and ended in October 1975 with the issuance of a Corridor Certificate. During this time period, 82 witnesses submitted nearly 1,870 pages of testimony at public hearings. The second stage ended with the issuance of a Certificate of Need on April 2, 1976, after hearings at which an additional 1,151 pages of testimony were collected. About this time the state also completed an Environmental Impact Statement on its own, which included opportunities for public comment. Finally, on June 3, 1976, the EQB issued the final route construction permit. In total, over 80 public meetings and hearings were held during the review process and almost 6,000 pages of transcript were collected. During the course of the review process, numerous modifications to the design of the line were made to accommodate local concerns. For example, the minimum height of the power lines was raised from 35 to 50 feet to prevent interference with aerial crop dusting and seeding and irrigation equipment.

In the aftermath of the siting board's approval of the project, nine separate lawsuits were filed seeking to have the approval overturned. The suits were consolidated by the Minnesota Supreme Court and the case was heard by a special three-person panel of District Court judges appointed by the Supreme Court. Approval of the project by the siting board was upheld by this panel on July 15, 1977, over one year after the final siting board action and more than two years after the regulatory agency review process began. The Supreme Court upheld the panel's decision on September 30, 1977.

While the formal review and appeal of the siting permits was underway, several other actions took place which were designed to alleviate the concerns felt by the project's opponents. For example, the EQB requested the state Department of Health to conduct a thorough study of health and safety effects of EHV transmission lines, which was completed in October 1977. The major finding, unfortunately, was that insufficient data existed to define public health impacts from power lines. The Governor also became personally involved in a number of instances. First, he proposed the establishment of a science court to grapple with the public health issue. A Technical Review Committee was, in fact, eventually established in 1980, but UPA and CPA refused to delay construction to await the results of additional research. In February 1977 the Governor's office retained the American Arbitration Association to attempt to resolve opinion differences through arbitration. During this time, the Governor even made surprise visits at the homes of the project's opposition leaders.

Construction of the Minnesota portion of the power line began in October 1977 and lasted for approximately one year. Despite the unsuccessful challenge to the project during the regulatory review and appeal process, opponents to the project continued to press their concerns, mainly through public demonstrations, which occasionally led to violence, vandalism, and intimidation of construction workers. Over $2 million worth of equipment damage, including the destruction of 16 steel power line towers and 10,000 insulators, was blamed on vandals. About $5 million was spent for a private security force which worked round the clock during construction.

Additional local and state police personnel were also assigned to patrol the construction zones. At one point the Minnesota Governor ordered 200 State Patrol officers into the area. Nonetheless, protests continued and scores of arrests were made and crowd dispersion actions, such as mace spraying, were undertaken. Protestors counterattacked at one point by spraying the State Patrol with liquid ammonia fertilizer. In another incident, a security guard and a local sheriff's deputy were shot at by an alleged vandal. Several arrests were made and one conviction resulted from this incident.

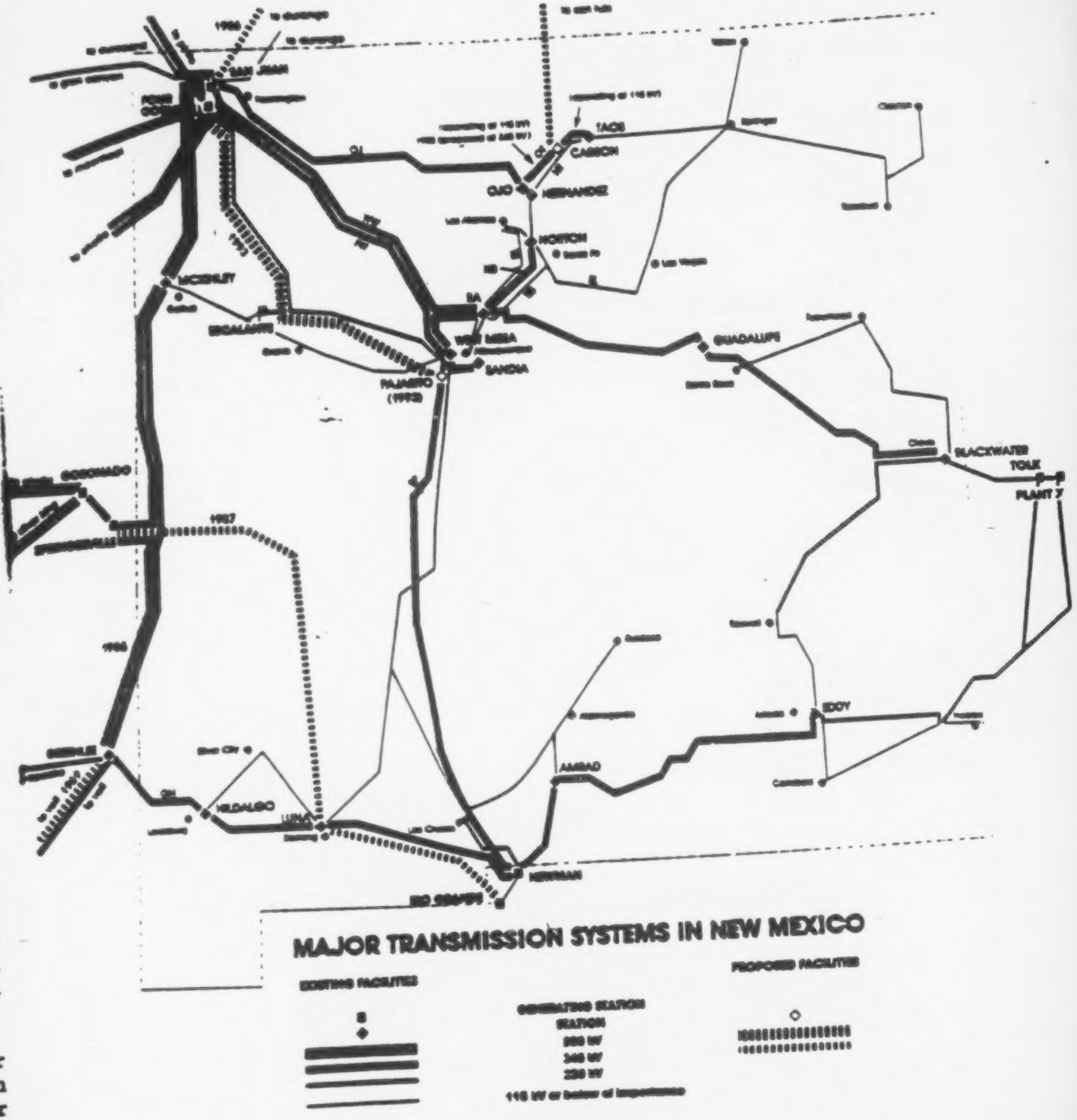
Despite this interference the power line was completed in late 1978 and it has been operational since April 1979. However, the magnitude of public opposition to the project, especially during the construction phase, attests that the concerns of a number of interest groups were not satisfactorily accommodated during the certification and licensing process. The Coal Creek project example demonstrates clearly the implications of failure to resolve a perceived mismatch between the recipients of the benefits of long distance transmission projects and the interest groups which are subject to some of its costs. Despite the existence of a siting process in Minnesota slanted toward the solicitation and resolution of public concerns and the active involvement of Governor's office as a mediating force, the Coal Creek experience shows how difficult the crafting of a long distance transmission line project can be.

The Ole Project

The Ole project involves the construction of a 345 KV AC transmission line to connect two existing EHV transmission lines owned by Public service Company of New Mexico (PNM). The line, approximately 70 miles long depending on the selected route, would provide a link between the Ojo power line, which connects the utility's San Juan Generating Station with portions of northern New Mexico, and the Norton switching station, from which power can be supplied to major power demand regions in central and northcentral New Mexico including the government laboratories at Los Alamos and the city of Albuquerque. The project, in effect, extends the San Juan to Ojo line to Norton and hence it is frequently called the Ojo Line Extension, or Ole, project (see maps).[63] Anticipated benefits of the project include increased transmission capability in Los Alamos and economic and reliability benefits to the state's transmission grid through improved system interconnection.

Several possible transmission line corridors could potentially be followed to accomplish the linkage proposed by the Ole project. A number of proposed configurations, called the "mountain" routes, travel largely through National Forest land across the Jemez mountains. Other configurations, termed the "valley" routes, follow largely private and Pueblo Indian lands through the Espanola Valley.

In addition to the forest lands, administered by the U.S. Forest Service, and the Pueblo Indian lands, administered with the approval of the U.S. Bureau of Indian Affairs, other federal lands administered by the National Park Service and the Bureau of Land Management are within the general vicinity of proposed routes. Because of the involvement of several federal agencies in granting rights-of-way for the project regardless of the final route configuration, completion of an Environmental Impact Statement (EIS) for the project was required under provisions of Section 102(2)(c) of NEPA.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FOUR CORNERS
TAOS
CARSON
OJO
HERNANDEZ
NORTON
Los Alamos
Santa Fe
Las Vegas
Springer
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WEST MESA
SANDIA
PAJARITO
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ESCALANTE
MCKINLEY
GUADALUPE
Santa Rosa
BLACKWATER
Clovis
TOLK
PLANT X
CORONADO
SPRINGERVILLE
1987
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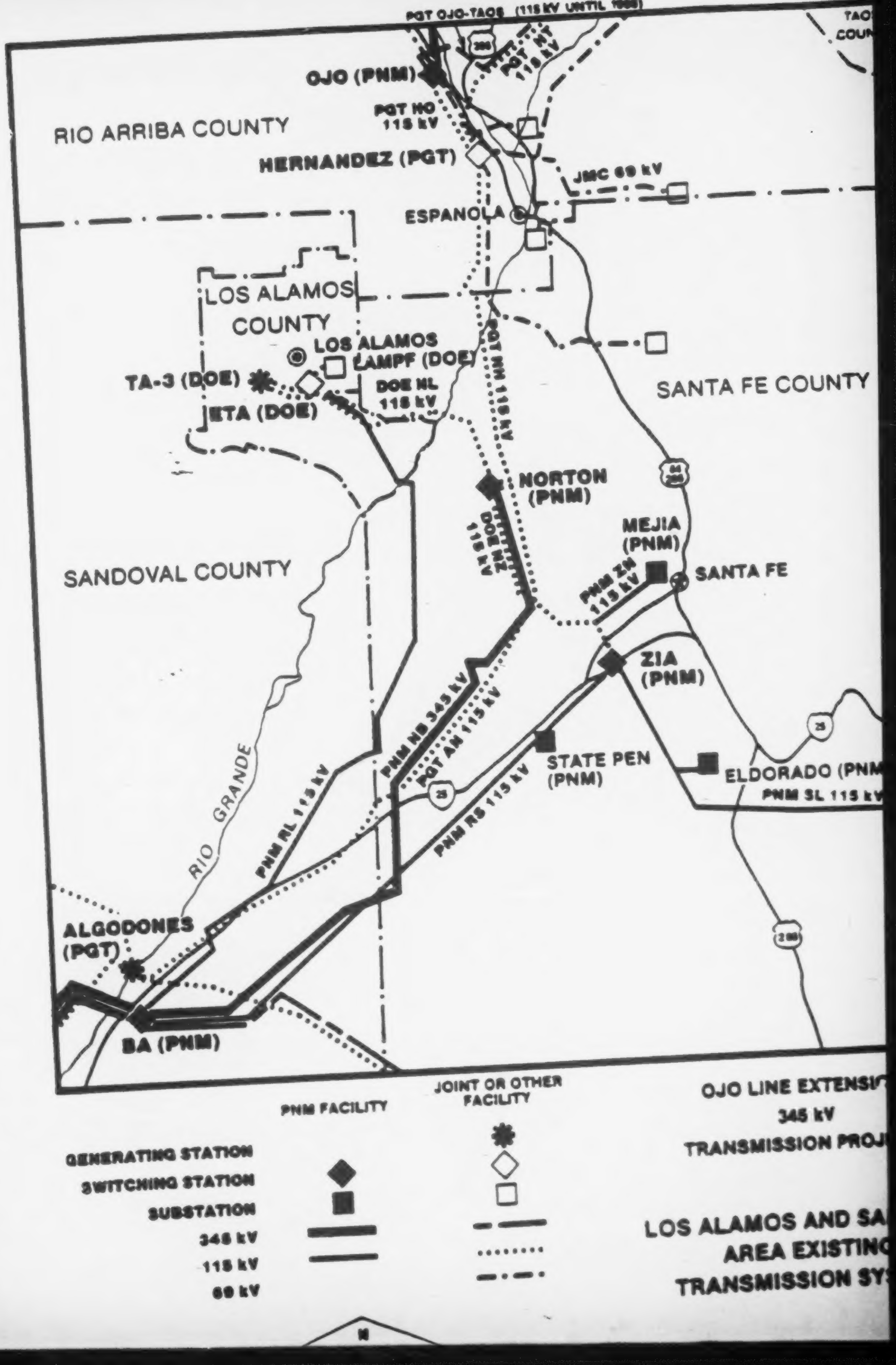
GREENLEE
HIDALGO
LUNA
Deming
Silver City
Las Cruces
AMRAD
Alamogordo
Ruidoso
Roswell
Artesia
EDDY
Carlsbad
Hobbs
NEWMAN
RIO GRANDE
EXISTING FACILITIES
GENERATING STATION
STATION
345 kV
230 kV
115 kV or below of importance
PROPOSED FACILITIES

MAJOR TRANSMISSION SYSTEMS IN NEW MEXICO

FIGURE 1-1


PGT OJO-TAOS (115 kV UNTIL 1986)
TAO
COUN
285
PGT NT 115 kV
OJO (PNM)
PGT HO 115 kV
RIO ARRIBA COUNTY
HERNANDEZ (PGT)
JMC 69 kV
ESPANOLA
LOS ALAMOS COUNTY
LOS ALAMOS
LAMPF (DOE)
TA-3 (DOE)
DOE NL 115 kV
ETA (DOE)
PGT NM 115 kV
SANTA FE COUNTY
NORTON (PNM)
DOE NZ 115 kV
84 285
MEJIA (PNM)
SANDOVAL COUNTY
PNM ZM 115 kV
SANTA FE
ZIA (PNM)
25
PNM NB 345 kV
PGT AN 115 kV
STATE PEN (PNM)
ELDORADO (PNM
PNM SL 115 kV
RIO GRANDE
PNM RL 115 kV
25
PNM RS 115 kV
285
ALGODONES (PGT)
BA (PNM)
PNM FACILITY
JOINT OR OTHER FACILITY
GENERATING STATION
SWITCHING STATION
SUBSTATION
345 kV
115 kV
69 kV
N

OJO LINE EXTENSI
345 kV
TRANSMISSION PROJ

LOS ALAMOS AND SA
AREA EXISTING
TRANSMISSION SY

The environmental analysis process began in early 1984 with the selection of the Bureau of Indian Affairs as the lead federal agency for the environmental review process, in view of the possible impacts of the Ole line on Indian Pueblo lands and on lands deemed sacred to Indian cultures in New Mexico. A Notice of Intent to prepare an EIS was announced in the Federal Register on July 25, 1984. A "scoping" process was then initiated to solicit input as to the significant issues which needed to be addressed in the EIS. Five public hearings were held followed by a public comment period for submission of written statements which ended on September 30, 1984. Eleven critical issues were identified for further in-depth analysis.

Completion of the Draft EIS took the BIA about one year. The document, spanning several hundred pages, was released for public review on October 22, 1985. The initial deadline for public comment was January 2, 1986, but this deadline was extended twice until the end of the month. During the comment period four public hearings on the Draft EIS were held. In total 151 written comments and 62 oral statements were catalogued by the BIA. Although the comments addressed a large number of issues, four concerns appeared to predominant in the comments, as follows:

o Need. Many parties including environmental groups, Pueblo Indians, Espanola Valley citizen associations, and the New Mexico State Energy and Minerals Department questioned whether the power transmission capability added by the Ole project was needed to supply future electricity demand. Alternative lower demand projections were offered based on enhanced conservation and load management programs. Higher projections of available electricity supplies were also outlined including contributions from cogeneration, out-of-state power imports, and other electricity sources not dependent on the Ole Project. As part of the NEPA process, the BIA was required to analyze a "no-action" alternative of not proceeding with the project. Opponents to the project frequently sited lack of need as the rationale for adoption of the no-action alternative.

o Impacts on Valley Lands. Associations representing residents of the Espanola Valley, including Pueblo Indians and residents of small, predominantly Anglo and Hispanic communities, raised issues related to the visual impacts of the power lines, disruptions of life styles and livelihoods, and public health threats from exposure to the electrical field generated by the line if it was situated along the proposed valley routes.

o Desecration of Sacred Pueblo Indian Sites. Pueblo Indian organizations and environmental groups complained that the proposed mountain routes would pass close to a number of sites deemed sacred to Native American cultures in New Mexico.

- Impacts on Wilderness Areas. A number of environmental groups complained of high visual impacts and other adverse environmental effects in the Santa Fe National Forest, such as on wildlife, if the line was built along the proposed mountain routes.

The BIA reviewed the public comments and published a Final EIS on the project on August 15, 1986. The Final EIS contained over 800 pages, including copies of all public comments, and weighed over 5 pounds. In it, the BIA endorsed as a proposed action construction of the Ole line along one of the mountain configurations. Complete environmental reviews of several mountain and valley routes were included in the EIS as well as a discussion of the no-action alternative. On September 26, 1986, the New Mexico BIA office issued a Record of Decision which specifically endorsed one mountain route, thereby clearing the way for the issuance of the requisite federal agency rights-of-way.

Shortly thereafter, several organizations, including the Sierra Club, another environmental group called Save the Jemez, a number of Indian Pueblos, and the New Mexico Attorney General's

Office appealed the Record of Decision to the Bureau's Director in Washington DC.[64] The appeal was rejected several months later. The appellants then pursued their objections in a lawsuit filed in U.S. District Court. The lawsuit alleges that the Final EIS inadequately complies with the requirements of NEPA by, for example, failing to establish a need for the project, and that the BIA approval of the mountain route violates the federal Indian Religious Freedom Act by endangering Native American sacred sites.

The case is expected to come to trial beginning in the Spring of 1988. Until and unless the case is finally resolved supporting the selection of a particular transmission line configuration in compliance with NEPA, the federal rights-of-way will not be issued and it is unlikely that the utility will submit an application to the New Mexico Public Service Commission thereby initiating the state agency approval process.

The Washington DC Loop

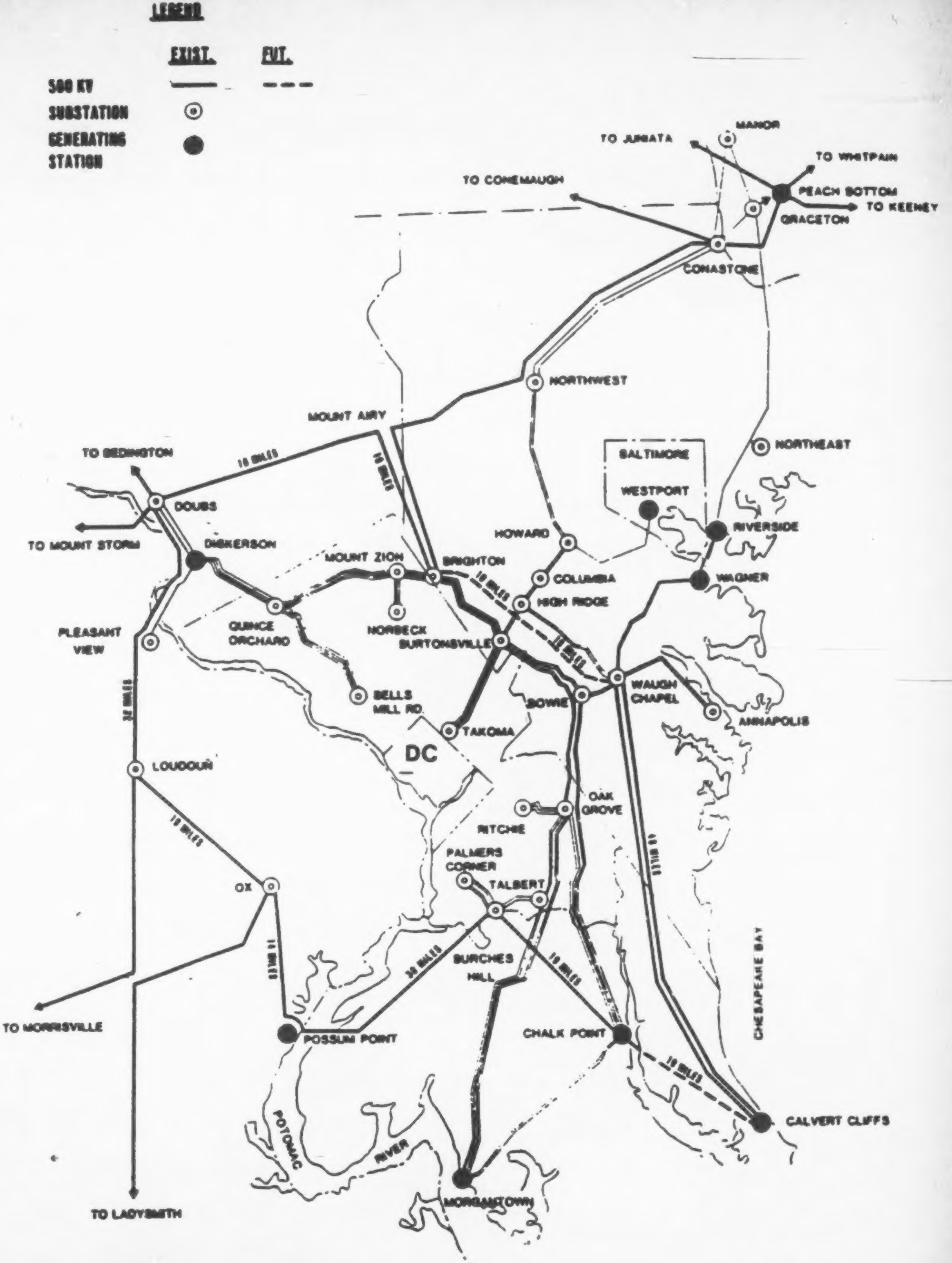
Since an interutility agreement was signed by utilities in the Washington DC area in 1972, several stretches of 500 KV transmission lines have been built as part of what is envisioned as a loop of 500 KV lines surrounding the nation's capital. The loop was designed to improve reliability of service for a number of utilities, mainly Baltimore Gas and Electric Company, Virginia Electric and Power Company, and the Potomac Electric Power

Company, and to improve transmission capability among mid-Atlantic states. Completion of the loop would provide up to 5000 MW of regional power transfer capability to the area.[65]

All sections of the loop have been constructed with the exception of three small stretches including a 10.5 mile stretch from Brighton to High Ridge, Maryland (see map). Failure to gain final authorization to construct this stretch has delayed completion of the loop. Nearly 12 years have elapsed since the initial application to build this section was filed.

Planning for the Washington Loop began in 1965 with the formation of the East Central Coordinated Interregional Study Group composed of representatives from a number of utilities. The group produced a study in 1967 recommending consideration of a loop project and the need for such a transmission line was confirmed in another study performed by a smaller group of utilities and released in October 1969. The project itself was launched in 1972 and most sections of the line were completed in the 1970's.

The problematic stretch between Brighton and High Ridge falls in the service area of the Potomac Electric Power Company (PEPCO). The company filed on July 26, 1976, for a Certificate of Public Convenience and Necessity (CCN). Significant opposition to the project developed among residents of Howard and


LEGEND
EXIST.
FUT.
500 KV
SUBSTATION
GENERATING STATION
TO JUNIATA
MANOR
TO WHITPAIN
TO CONEMAUGH
PEACH BOTTOM
TO KEENEY
GRACETON
CONASTONE
NORTHWEST
MOUNT AIRY
NORTHEAST
BALTIMORE
WESTPORT
TO BEDINGTON
10 MILES
10 MILES
DOUBS
RIVERSIDE
HOWARD
TO MOUNT STORM
DICKERSON
MOUNT ZION
BRIGHTON
WAGNER
COLUMBIA
10 MILES
HIGH RIDGE
PLEASANT VIEW
QUINCE ORCHARD
NORBECK
BURTONSVILLE
10 MILES
WAUGH CHAPEL
32 MILES
BELLS MILL RD.
BOWIE
ANNAPOLIS
TAKOMA
DC
LOUDOUN
OAK GROVE
RITCHIE
10 MILES
PALMERS CORNER
TALBERT
48 MILES
OX
10 MILES
30 MILES
BURCHES HILL
10 MILES
CHESAPEAKE BAY
TO MORRISVILLE
POSSUM POINT
CHALK POINT
10 MILES
CALVERT CLIFFS
POTOMAC
RIVER
MORGANTOWN
TO LADYSMITH

NOTE: LINES ARE SHOWN FOR GENERAL CONCEPT, AND DO NOT INDICATE ACTUAL ROUTE LOCATIONS.

ADAPTED FROM MAP PROVIDED BY PEPCO

Figure 2

The Washington 500-kV loop

Montgomery counties, Maryland through which various configurations of the proposed line traversed. PEPCO made several alterations to its initial proposal in response to the concerns of opponents in an amended application filed on April 7, 1977. The project was reviewed first by the Maryland Department of Natural Resources, the lead transmission line siting agency in the state. After an initial favorable ruling on the project by the Department, formal hearings on the project began. The hearings lasted nearly a year, ending on May 23, 1978, after collection of over 6,000 pages of testimony from over 70 witnesses. Two public meetings were also held at which 47 people spoke.

The principle point of contention involved the visual impact and potential health threats of the transmission line in the densely populated suburban areas through which it was proposed to pass. This concern led some parties to propose a number of alternate siting configurations designed to avoid certain areas of concern and it led others to investigate the need for the overall loop project and to argue that its completion was not necessary to ensure reliable transmission capability. For example, the government of Howard County denied that the line was needed, but concluded that if it was built, it should be constructed along a route falling largely in Montgomery County. On the other hand, the government of Montgomery County believed that the line was needed, but supported a route traversing Howard

County for more than two-thirds of its distance.

On November 16, 1978, the Department of Natural Resources recommended that the project proceed and endorsed a route largely falling mostly in Howard County. Six months later on April 6, 1979, the Hearing Examiner for the Maryland Public Service Commission (PSC) issued a proposed order granting the CCN. By this time, the approval process had consumed nearly three years.

Several opponents to the project then appealed the proposed order to the Public Service Commission. That appeal was denied 11 months later only to be followed by several motions for a rehearing before the Commission filed on April 4, 1980. Moreover, the order was appealed to the Montgomery County Circuit Court on April 3, 1980. Under state law, the Commission was forced to delay consideration of the motions for rehearing until the Circuit Court made its ruling. After a lapse of more than a year during which the case was never brought before the Court, the appeal was withdrawn and the PSC once again took up the rehearing motions.

The motions were denied on July 2, 1981, only to be followed by further appeals back to the Montgomery County Circuit Court and to Circuit Courts in Howard and neighboring Prince George's counties. In March 1982 the cases were consolidated in the court in Howard County, but consideration of the case did not proceed far before a legal battle tangential to the transmission line issue emerged concerning the rights of one of the plaintiffs to take oral depositions of individual members of the Maryland PSC. Nearly two years and two court decisions later, the Maryland Court of Appeals ruled on July 12, 1984, that Commissioners could not be deposed. Some 15 months more elapsed before the Howard County Circuit Court upheld the granting of the CCN on October 14, 1985, more than 6 years after it was initially approved by the Hearing Examiner.

Construction of the transmission line has still not begun, despite issuance of the CCN. PEPCO currently is working to obtain variances from local zoning regulations, although it is not clear from state law whether such variances are required for a project which has been issued a CCN.

CONCLUSIONS

The complexities involved in the siting of large transmission line projects are significant, especially with regard to multi-state projects designed to promote interutility power sales. Nevertheless, the simple fact is that most power line projects are successfully sited in a timely fashion if not to the satisfaction of all the interest groups participating in the decisionmaking processes. Even in the face of increased demand for new transmission capacity anticipated by electric utility industry restructuring proposals, current siting procedures are probably adequate, although inefficient.

A number of impediments to transmission line siting can be clearly identified, although sound recommendations to remove those impediments are not so obvious. A dearth of information about future transmission needs and a lack of communication among regulatory agencies appear to encourage confusion in siting processes. Conflicting regulatory agency priorities, objectives, and jurisdictions can add Byzantine elements to siting processes. Multiple decisionmaking procedures within overall siting procedures permit interest groups to pick the decisionmaking arena of their choice in which to express their views or to repeat the same concerns before different audiences recognizing that a single success can achieve their objective.

Many proposals to alter siting procedures could have negative as well as positive effects in practice, sometimes leading to solutions which create conditions as bad or worse than the problems they are designed to correct. For example, creation of "one-stop" siting entities with final decisionmaking authority can greatly simplify and expedite siting, but it can also undercut public participation, information dissemination, and the exercise of statutory responsibilities by other regulatory agencies. Bolstering long range transmission planning can provide more useful analytical information for decisionmakers, but collection of this information can add time and costs to siting processes and identify new uncertainties and information needs.

Most of the proposals to address the impediments to transmission line siting discussed in this paper are being tested to a greater or lesser degree in specific states or regions of the country. Perhaps the most prudent advice is to encourage the continuation and expansion of these efforts to improve siting procedures. Greater attention to the implementation of innovations to traditional siting protocols under virtual "test" conditions coupled with redoubled efforts to share the resulting experiences and insights could produce significant improvements to siting processes over time without undercutting along the way what appears to be a basically sound process.

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59. Ibid. Attached letter to Secretary Herrington.

60. National Regulatory Research Institute, op. cit. Page 159.

61. Westview Special Studies, op. cit. Pages 8 through 11.

62. Unless otherwise noted this case study was drawn from a chapter in Dennis Ducsik book, op. cit. entitled "Public Participation in Routing Transmission Lines: A Program Born of Adversity" written by Dan McConnon of UPA and from an article, "The Minnesota Power-line Wars" in the July 1983 issue of the IEEE Spectrum written by Sheldon Mains of the Minnesota Environmental Quality Board.

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64. Information about events after issuance of the notice of Decision was obtained from interviews with representatives from an environmental group, state agencies, and several Indian Pueblos affected by the project.

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OTA DRAFT WORKING PAPER

ENVIRONMENTAL EFFECTS OF INCREASED COMPETITION IN THE ELECTRIC POWER INDUSTRY

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CONTENTS

I. Introduction 1

II. Basic Environmental Standards 6

III. Industry-Wide Environmental Issues 9

- The Fuel Cycle 9
- Combustion 13
- Transmission and Distribution 15

IV. Scenes of Change: The Changing Electric Utility Industry 20

V. Case Studies 44

- 1. The Transmission Quagmire: The New York Power Lines Project, Colstrip, Coal Creek, and Klein Independent School District 45
- 2. Bidding in Massachusetts: A Glimpse of the Future? 55

VI. Conclusions 63

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ENVIRONMENTAL EFFECTS OF INCREASED COMPETITION IN THE ELECTRIC POWER INDUSTRY

I. INTRODUCTION

Change is sweeping through the electric utility industry at a pace unseen since the 1930s.[1] Driven by events in the 1970s, centrifugal forces have struck the once monolithic electricity utilities and divided them. The divisions are shown most clearly by the many ways that utilities now view their own future and the future of their business.

As late as the early 1970s, there was general consensus in the electric utility industry about the shape of the future. The future, the industry leaders believed, would look largely like the past. That meant a world of generally rising demand for electricity, driven by ever lower costs as larger plants brought economies of scale. The future structure of the industry also was clear: electric utilities were a natural monopoly, and would always exist as regulated businesses with a geographic franchise, a stipulated rate of return, and an obligation to serve within its franchise.

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[1] See statement of Martha O. Hesse, Chairman of the Federal Energy Regulatory Commission, before the House Energy and Commerce Subcommittee on Energy and Power, September 10, 1987, pp. 1-3. For a good discussion of the regulatory history of the electric power industry during the 1920s and 1930s, see Kenneth S. Davis, ROOSEVELT: THE NEW YORK YEARS.

By the late 1970s and into the 1980s, it became clear that the industry vision had been clouded. The present as it evolved during the so-called "energy crisis" years was far different than utility executives expected. The economies of scale that had characterized the 1960s proved chimerical. For some utilities, nuclear power turned from a dream into a nightmare. And as costs escalated, consumers began using less electricity and finding ways to use it more efficiently.

As demand for electricity fell, the large central-station plants that the utilities had ordered to serve the expected growth in their markets often became white elephants, producing excess power at high prices. State regulators responded by revitalizing a little-used regulatory doctrine known as "prudence," declaring that large portions of the costs of these projects had not been prudent and could not be recovered in rates.[2] But prudence reviews are a stop-gap, after-the-damage measure.

Few people who had any experience with troubled utility building programs during the 1970s and 1980s, whether utility executives, environmentalists, ratepayers, or public officials emerged with much trust in the status quo. In the blunt words of New York Attorney General Robert Abrams, pondering two nuclear projects gone sour: "The present system of direct ratepayer financing of utility construction clearly warrants abolition. Under this system, the utilities continued the construction of Nine Mile Point Two and Shoreham long after unregulated businesses would have terminated the projects."[3]

As the familiar regulatory environment began crumbling, electric utilities found themselves facing additional challenges from the public in the form of continued and increased demands for better environmental performance. Responding to unrelenting demands from the public, federal and state environmental, health, and safety regulators during the 1970s insisted on costly new expenditures for pollution control and public health and safety.

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[2] For a characteristic industry description of the prudence phenomenon, see "Generating Change, Virginia Power's Chief Wants More Competition," Washington Business, Nov. 30, 1987, pp. 1, 22-23.

[3] Robert Abrams, Brief on Exceptions, State of New York Public Service Commission, Case 29409: "Proceeding on motion of the commission as to the plans for meeting future electricity needs in New York State."

Environmental concerns have long had been a key item on the public policy agenda of the nation's electric utilities, the largest consumers of raw energy in the nation[4] as well as the sole commercial market for nuclear power plants. Environmental issues have led to important legislation to regulate utility air, water, and waste emissions and to improve public health and safety practices. At the local level, land use issues, particularly plant siting and power line corridor siting, have challenged the utility inudustry.

One result of the push for conservation and alternate generation was the 1978 Public Utilities Regulatory Policies Act (PURPA). After a somewhat slow start, by 1980 PURPA was having a major impact on future electricity supply, primarily because it encouraged co-generation, or the generation of electric power by industries who also raise steam for industrial processes.

There is nothing new about co-generation. Indeed, it was the dominant source of electric supply during the early years of the electric utility industry.[5] However, once utilities began building their own generating plants, they were reluctant to buy power from third parties and generally refused to offer prices acceptable to outside generators until forced to do so by PURPA.

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[4]. Electric utilities used about 36 percent of all the energy consumed in the U.S. in 1985 (26.5 quads out of total consumption of 73.8 quads). New England Energy Inc., "Review and Analysis of Energy Markets," September 30, 1986, p. 35.

[5]. See Davis, op. cit.

Despite opposition from some in the electric utility industry, cogeneration boomed in the 1980s, fueled by clean, low-cost natural gas burned in combustion turbines which offer higher efficiency than conventional steam turbine generators. These plants often were able to produce power cheaper than the local electric utility, while meeting the most stringent environmental regulations.[6] At the same time, The Powerplant and Industrial Fuel Use Act of 1978 (passed as a companion measure with PURPA) banned use of gas in new electric utility plants. Also, many cogenerators fell below the minimum size limits for the more stringent environmental regulations -- even though their cumulative impact was significant. Thus, an environmental loophole existed.

Dissatisfaction with PURPA by some utilities, principally in California and Texas, coupled with the general dissatisfaction with the economic and regulatory status quo, has led the Federal Energy Regulatory Commission to consider changes in the way the law is implemented.[7] One element the agency is considering is competitive bidding to determine the price for power from cogenerators and other qualified bidders.

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[6] Often, gas turbines were less expensive than utility rates because of the rate shock effects of a large baseload plant just coming on line. On Long Island, for example, the rate shock effect of the Shoreham nuclear plant led Grumman, the area's leading employer, to install gas turbines with 50 megawatts of capacity rather than pay Long Island Lighting Co. rates.

It would be unfortunate if the changes that are impending have unanticipated effects on the environmental performance of the utility industry, or on gains in energy efficiency and conservation that utilities have been making the 1980s. This paper examines each of the OTA's five scenarios for the future of the electric utility industry from the standpoint of how those changes might impact the environment, natural resource conservation, and energy efficiency.

II. BASIC ENVIRONMENTAL STANDARDS

In analyzing how changes in the electric utility industry will affect environmental issues, it is important to describe some environmental reference points. These guiding policies and principals, firmly embedded in federal and state laws and regulations, can help policymakers evaluate the effects of different policy options. If a proposed policy violates one of the standards, that should serve to raise a warning that the policy should receive further scrutiny.

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[7] See "Remarks by FERC Chairman Martha O. Hesse," Energy Daily Utility Conference, Washington D.C., November 6, 1987. Also, "Remarks of Charles A. Trabandt, Commissioner," Energy Daily Utility Conference, Washington D.C., November 5, 1987.

Energy conservation is preferable to new supply. This standard is embodied as national policy in several of the laws Congress passed in the mid-1970s, (EPCA, ECPA, etc.). As one analyst puts it, "A dollar invested in wise energy conservation makes more net energy available than a dollar invest in developing new energy resources."[8] Conserving a kilowatt of power serves the same end as generating a kilowatt of power, but without the pollution that is inevitably associated with generation, and with no need for transmission and distribution. Public policy should be directed toward the maximum amount of conservation before any generating strategies can come into play.

All costs must be fully internalized. In the past, electric utilities kept the price of power low by externalizing their environmental costs. In the 1950s, for example, utilities generally did not control particulate emissions, which kept rates low. But the particulate emissions had public health costs. Similarly, continued sulfur dioxide emissions from older, uncontrolled utility plants in the Midwest has a social cost, in the form of acid rain.[9] The Clean Air Act of 1970 and the 1977 amendments rest on the principle that internalizing costs is a key to air pollution control.

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[8] Denis Hayes, "Energy: The Case for Conservation," Worldwatch Paper 4, January 1976, p. 23.

[9] See OTA, ACID RAIN AND TRANSPORTED AIR POLLUTANTS: IMPLICATIONS FOR PUBLIC POLICY, June 1984.

Market principles should pertain where a marketplace exists. Competition can serve the interests of consumers and the environment when there is true competition. Market economies are far preferable to regulation, from an environmental standpoint, because they set prices and allocate resources more efficiently, if social and environmental protection costs are fully internalized. As a recent analysis conclude, "Getting the prices right is more than a game economists play. Properly set energy prices that reflect their true costs minimize behavioral distortions and uneconomic fuel substitutions If energy producers and consumers receive incorrect price signals, resources are misallocated and economic growth and development are stunted."[10] The converse of this is that regulation is necessary where competition does not exist. The mere assertion that a market is competitive does not make it so, but policy developments that attempt to eliminate monopolies and monopsonies are welcome.

Environmental and public health values must have at least the same weight as economic values. Many federal environmental laws (NEPA, Atomic Energy Act, Clean Air Act, Safe Drinking Water Act, etc.) require that environmental and public health values supersede economic values. The 1986 Electric Consumers Policy Act mandates that the Federal Energy Regulatory Commission give the same value to environmental concerns such as wildlife as economic concerns such as jobs.

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[10] Mark Kosmo, "Money to Burn? The High Costs of Energy Subsidies," World Resources Institute, October 1987, p. 6. Also see William U. Chandler, "The Changing Role of the Market in National Economies," Worldwatch Paper 72, September 1986.

III. INDUSTRY-WIDE ENVIRONMENTAL ISSUES

The electric utility industry faces perhaps the broadest array of environmental issues of any industry in the nation. And that has been the fact for many years. Because electric utilities are so pervasive in the life of the U.S., and because their manufacturing facilities are so large, the industry has been at the cutting edge of environmental disputes, and a world leader in developing environmental control and monitoring technology.

As the industry's structure changes, either through evolution or by conscious public policy, there is no reason to believe that environmental issues will recede into the background. Indeed, it is likely that environmental concerns will continue to be a major element in the industry's structural dynamics.

Thus is it worthwhile to sketch out the environmental issues that arise in the industry, regardless of its structure. These include fuel cycle issues, combustion issues, and transmission and distribution issues.

The Fuel Cycle

The first set are fuel-cycle issues. For coal, this means issues related to the mining of coal, transportation, and waste disposal. Environmental issues related to burning coal are discussed under combustion. The environmental[11] issues with coal start with land-use. One set of issues is use of public lands, primarily an issue in the Western U.S. Another set of land use issues relates to conflicts between coal mining and special categories of public lands such as national parks, wildlife refuges, and wilderness areas. In the East, land use issues relate to impacts of surface mining on private lands, and land-use impacts of underground mining, such as subsidence related to the growing use of longwall mining technology. Transportation of coal from mine to powerplant can also lead to environmental disputes. The two-decade-old dispute over coal slurry pipelines is a case in point. Finally, disposing of coal waste products -- fly and bottom ash, scrubber sludges, and wastes from advanced technologies such as coal gasification -- can set off environmental concerns because of concentrations of heavy metals and toxic organic compounds.[12]

The oil and gas fuel cycle raises some of the same public lands conflicts, particularly related to leasing for exploration and production. Onshore, there is environmental tension between opening up lands for oil and gas development and preserving wilderness, as in the current dispute over exploration of the Artic National Wildlife Refuge. Oil and gas adds another public lands issue, as well: outer continental shelf leasing. Offshore, there have been protracted disputes about the environmental impacts of exploration and production on the Outer Continental Shelf, pitting energy developers against fishing interests. There is also a toxics issue associated with oil and gas drilling. EPA toxicological studies have shown that drilling muds and fluids may meet RCRA requirements, although the agency has proposed exempting them from full regulation.

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[11] There are also significant health issues with regard to coal mining, including mine accidents and fatalities, and black lung disease.

[12] The Resource Conservation and Recovery Act of 1979 exempts some, but not all, coal wastes from the most stringent requirements for land disposal.

The nuclear fuel cycle has a number of well-known environmental[13] issues. Among them: land disturbances caused by mining, milling and mill tailings disposal, and spent fuel disposal. In addition, low-level waste disposal is becoming an increasingly important environmental issue, particularly as the states maneuver in and out of regional compacts under the 1985 low level waste amendments. Looming in the background of the nuclear fuel cycle is also the issue of reprocessing. Should the economics of reprocessing change dramatically and the nuclear industry attempt to reinstate reprocessing plan, this will set off an enormous debate over both environmental issues and nonproliferation strategies.

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[13] There are also worker health issues associated with the nuclear fuel cycle, particularly the high levels of lung cancer found in uranium miners.

One area where environmental concerns over fuel cycle issues is just beginning to form is waste-to-energy. As local governments face growing piles of trash and diminishing access to landfills, they are increasingly turning to trash-burning facilities. PURPA provides a powerful boost to these facilities, by guaranteeing a market for the power at the avoided cost rate. As these facilities are proposed, local citizens have raised objections related to collection and transportation of the waste, plans for disposal of the potentially hazardous bottom and fly ash, and plans for further landfills to dispose of the ash. Leachates from the trash waste piles can raise water quality issues, which is particularly troubling because regulation of groundwater pollution is currently in a state of flux, with neither state nor federal regulators clearly in charge. Waste-to-energy projects often are heavily subsidized: The builder has access to low-cost capital through municipal borrowing and pollution control bonds: the operator is paid to take the trash, turning traditional costs for fuel into a revenue stream; and the project earns a revenue stream from power sales.[14]

Even hydroelectric projects have environmentally-sensitive fuel cycle issues, with water defined as the fuel. Hydro proposals often have public lands and wilderness components, particularly in the West. Also, hydro projects, including the kinds of small hydro that PURPA encourages, frequently run afoul of recreation and scenic values, and often have severe impacts on fish and wildlife.[15]

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[14] Another powerful subsidy is an EPA regulation that exempts facilities that burn hazardous or toxic waste from regulation if the waste is used to generate energy.

Combustion

In addition to the fuel cycle issues, electric utility generation mix and combustion of fuels raise a different set of issues. Fossil fuels raise a whole series of air quality issues, including SO2, NOX, and CO2 emissions. There are also issues of scale that arise here. Oil and gas have found their most recent markets in smaller plants, particularly combustion turbines, while coal plants tend to be much larger. However, developing coal technologies -- particularly atmospheric fluidized bed and integrated, combined-cycle coal gasification -- also are targeted at smaller, modular units suited for cogeneration and PURPA applications.

Until quite recently, there was a serious discontinuity in regulating coal-fired boilers, which gave smaller boilers much more lenient sulfur dioxide standards than large boilers. The

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[15]. For a good example of the kinds of adverse impacts that hydro development can pose, see the March 1988 FERC Environmental Assessment for the Hawks Nest project in West Virginia, and the U.S. Fish and Wildlife Service comments on the EA.

1971 New Source Performance Standards applied only to utility and industrial boilers of about 67 megawatts and above. But as a result of a law suit brought by the Natural Resources Defense Council and settled late in 1987, the 1.2 pounds per million Btu SO2 standard and 90 percent emissions reduction rule will apply to all fossil-fueled boilers above about 27 megawatts.[16] And EPA is on a schedule to apply the 1.2 standard to even smaller coal-fired plants by 1989.[17]

Trash burning facilities also raise a series of environmental issues related to combustion. In addition to the classic concerns about SO2 and NOX, trash facilities also produce dioxins, furans, and other toxic air pollutants[18].

Nuclear generation, of course, has a long and familiar list of environmental and public health disputes, including issues related to worker safety. Among the complex of issues that surround nuclear generation are routine air and water emissions, reactor safety, the source term, emergency planning, and the consumptive use of water (this is an issue in arid areas for any steam-generation technology).

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[16]. While 27 megawatts is rather large for a gas-fired combustion turbine or combined cycle project, it is on the smaller side for coal-fired boilers.

[17]. Telephone interview with David Hawkins, NRDC, 7 January 1988. Plants with a capacity factor of less than 30 percent and plants burning very low sulfur oil are exempted from the percentage reduction requirement. See also, "Small power plants now must meet pollution standards," Public Power Weekly, American Public Power Association, January 11, 1988.

[18]. Allen Hershkowitz, "Burning Trash: How It Could Work," Technology Review, July 1987, pp. 26-34. Also see Testimony of Dr. Houston Miller, George Washington University chemistry department, before Montgomery County Council (get date).

Transmission and Distribution

Finally, transmission and distribution raise another set of environmental issues. While these issues haven't received the national attention that has been the case with air quality or waste disposal, they have often been just as intense and fractious at the local level as the more traditional environmental disputes.

Transmission issues may become a greater part of the environmental debate in the future, as utilities change their spending patterns away from building plant and toward moving voltage. Transmission and distribution already consumes more capital than generation and, according to an Edison Electric Institute finance department survey, "the period 1986 through 1989 will see nuclear and coal generating plant expenditures down 40 percent; whereas, transmission expenditures will rise some 51 percent to $2.7 billion."[19]

Transmission and distribution are intimately tied into local land use and zoning, and disputes often take place in the institutional forums created for dealing with local land use and zoning problems, such as city, county and state zoning boards, boards of zoning appeals, and the like. Other venues for land use disputes over transmission and distribution can occur before state bodies that must license or permit a facility, in an eminent domain proceeding, or in state courts. Landowners who will see powerlines cross their property, particularly in urban or suburban areas but also in rural areas,[20] often believe the line will lower the value of their property. Consequently, the disputes can be very bitter and intense (See Case Study 1: The Transmission Quagmire).

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[19] Richard Braatz, "the Business and Financial Aspects of Electric Utility Restructuring," paper present at the Energy Daily annual utility conference, Washington DC, November 5, 1987.

Because they can extend for long distances, are often highly visible, and frequently pass through populated areas, siting power lines is usually a time-consuming and frustrating experience for the utility, regulators, and local citizens, with costly consequences.[21] Once a project has been sited and permitted, there can also be environmental disputes related to construction, including issues such as erosion and sediment

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20. Robert R. Thompson and William E. Phillips, "Agricultural Land Vale Changes from Electric Transmission Lines: Implications for Compensation," Right of Way, December 1985, pp. 24-27.

21. See remarks of Richard Disbrow, President, American Electric Power Service Corp., at OTA workshop, September 28, 1987.

control, soil compaction, destruction of forests, and the like.[22]

Once a power line is built and operating, a different set of impacts come into play, although these issues likely will have been raised earlier during the siting and permitting processes. Visual impact, impact on bird life,[23] audible noise and corona[24] effects[25], and, an area that has generated a lot of attention of late, bioilogical effects of electrical fields on wildlife, livestock, and human health.[26] Another environmental issue related to existing powerlines is the use of pesticides and herbicides to clear rights of way.

Visual impact plays a major role in transmission line disputes, in part because the visual presence of the lines often becomes a symbol of its total presence. The utility industry has attempted to design less visible structures, although that can drive up costs. Some analysts have suggested that the present of a visible line is "a negative feedback mechanism" that could serve to slow growth of electrical use, by confronting consumers with the costs associated with electricity use.[27]

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[22] For a good discussion of the environmental impacts of powerlines, see Federal Colstrip Transmission Corridor Study Project Team, "Developing Numerical Values to Estimate Potential Environmental Impact of Power Transmission Corridors," Bonneville Power Administration, Nov. 1978, appendix.

[23] Rene Males, EPRI Journal, March 1980, p. 49.

[24] Air ionized by the high electric fields at the surface of the conductor creates the corona phenomena.

[25] John A. Molina, Gerald A. Zerdy, Neil D. Lerner, and Dane L. Harwood, "Modification of Transmission LIne Audible Noise Spectra to Reduce Environmental Impact," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No. 4, April 1981.

[26] For a discussion of the evolution of environmental concerns about powerlines, see William E. Feero, "The Evolution of Electromagnetic Effects Issues," paper presented at the International Utility Symposium on Health Effects of Electric and Magnetic Fields, September 16-19, 1986, Toronto, Canada.

Existing powerlines can have an adverse impact on bird populations, including protected species such as the golden eagle, which use poles as perches for hunting and are "often electrocuted by contact with lines." There is also some evidence that overhead lines may increase avian mortality from collisions and changes in behavior, although not much data on this problem has been accumulated.[28]

Powerlines also emit audible noise, radio frequency and television frequency interference, all the result of corona discharges. Because corona discharge is largely a function of weather, these problems are also associated with weather phenomena, generally being a greater problem in rain or fog.[29] Corona noise is typically both low-frequency hums and buzzes, and random, high-frequency hisses and crackling. Studies suggest that the high-frequency component is more objectionable to listeners.[30]

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[27] Thomas W. Smith, John C. Jenkins, John S. Steinhart, Kathleen A. Briody, David Schoengold, "Transmission Lines: Environmental and Public Policy Considerations," Institute for Environmental STudies, University of Wisconsin-Madison, June 1977, p. 44.

[28] Males, op. cit., p. 49.

[29] Smith, Jenkins, STeinhart, Briody, and Schoengold, op. cit. p. 39.

Another product of corona discharge is ozone, a powerful oxidant that is a key precursor of smog. Ozone also has an affect on living tissue that is smilar to ionizing radiation, in that it causes tissues to break down and undergo chemical change. Ozone can irritate eyes, lungs, and circulatory systems of animals, including humans, and increase susceptibility to information and chronic disease through stress. It can also cause direct damage to vegetation.[31]

Powerlines may also have a more subtle impact on health. Evidence is accumulating that exposure to low frequency fields from powerlines and household appliances may be associated with or may promote cancer. The electric utility industry is devoting a greater share of its research dollars to this emerging field, trying to pin down the mechanisms that are at work, and determine what steps can be taken to prevent damage if it is occuring.[32]

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[30]. John A. Molino, Gerald A. Zerdy, Neil D. Lerner, Dana L. Harwood, "Modification of Transmission Line Audible Noise Spectra to Reduce Environmental Impact," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No. 4, April 1981, p. 2122.

[31]. Smith, et. al, op. cit., p. 35.

[32]. EPRI Journal, op. cit., pp. 4-15. See also Mart H. Malakoff, "Electronic Smog," Not Man Apart, March-April 1988, pp. 10-11.

Finally, maintenance and vegetation management can have environmental impacts with existing transmission lines. Utilities generally want to establish a shrubland environment under their powerlines, because shurblands last far long than grasslands, once undesirable trees are removed. Since 1945, utilities have applied chemical herbicides to control vegetation. Notes one study, "Knowledge of specific species and their ecosystem interactions were not used to correlate vegetation management practices with herbicide application until very recently. Rachel Carson's SILENT SPRING in 1962 points out the misuse of pesticides and the lack of available data on the effects of chemical treatments beyond the initial visible brown-out that results. The controversy concerning herbicide use is quite broad with no clear solution in sight."[33]

IV. SCENES OF CHANGE: THE CHANGING ELECTRIC UTILITY INDUSTRY

Analysts and observers of the electric utility industry generally conclude that some structural changes in the industry are inevitable, regardless of governmental action. But the experts are in wide disagreement about how deep and fundamental those changes are, or should be. Some advocate regulatory fine tuning within the current strucure (Scenario 1). Others propose changes mostly in how bulk power transfer among a broader range of players can be accommodated (Scenario 2). Another set of proposals would establish competitive bidding for all new power supplies as the determinant of avoided cost under PURPA (Scenario 3). Going beyond that, some have proposed ending the vertical integration of the industry, by spinning off all generation into competitive businesses (Scenario 4). Finally, there are proposals for a fully-deregulated generation sector, with transmission serving as a common carrier to all comers (Scenario 5)

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[33] Smith, et. al., op. cit., p. 32.

Each of these scenarios will have environmental consequences, which are often difficult to discern in light of the speculative nature of the proposals. Despite the inability to pin down the impacts with precision, it is still worthwhile to try to describe how the various scenarios might affect the environment.

Scenario 1: Strengthening the Existing Regulatory-Utility Bargain.

Not all electric utility industry executives are convinced that fundamental structural changes in the industry are needed or desirable. For the most part, these skeptics can be found among the utilities who have done well in the existing system, and the crux of their assessment of the current business environment for electric utilities is that timeless bit of country wisdom: "If it ain't broke, don't fix it."

The leader in this school of thought is American Electric

Power, a large, successful utility holding company based in Columbus, Ohio. AEP has offered a proposal for what he calls "rolling prudence," which is a state-based system of periodic reviews of construction projects, in advance of financial commitments, and an end to major disallowances after a construction project is finished.[34] AEP's views form the basis of the OTA scenario 1. In OTA's words, "Scenario 1 continues the existing regulatory scheme and electric power industry structure and reaffirms the regulatory-utility bargain with minor modifications of regulatory rules and procedures to improve the ability of utilities to attract capital for construction of new facilities and to assure a reasonable return to investors (e.g., "rolling prudence reviews"). Modifications of PURPA rules to correct perceived imbalances in avoided cost pricing rules for QF [PURPA qualifying facilities] power would also be allowed."

As with all the visions of the future sketched by OTA, Scenario 1 is a mixed bag of environmental problems and opportunities. The environmental advantages flow from the fact that scenario 1 is well-understood. As essentially the status quo with slight modifications, the first scenario presents issues that have been faced in the past, and relies on institutional arrangements that have been developed over the past 20 years.

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[34] John McCaughey, "Dick Disbrow: Dissenting With The Fashionable Utility Talk," Energy Daily, Nov. 23, 1987, p. 1.

With this scenario, we basically know where we stand on environmental issues.

The concept of "rolling prudence" also has some potential environmental benefits. It might prove easier to cancel some projects earlier in the construction process, before such enormous amounts of capital have been sunk in a project that cancellation becomes nigh on to unthinkable. Prudence is a doctrine that utility commissions have rediscovered recently, and applied with various effect. However, as New York Attorney General Robert Abrams observed, with regard to heavy disallowances for at Nine Mile Point 2 and Shoreham, "These findings of imprudence, salutary as they were, necessarily came too late to prevent vast expenditures which should never have been made."[35]

Utilities complain that the current system subjects them to too much risk, and there is merit in that complaint. But the current system also results in too many white elephants, where the high capital costs render lower operating costs meaningless unless the utility is willing to write off the sunk costs and a return on them. This has occurred time after time with new nuclear plants, such as Nine Mile Point 2, Shoreham, Diablo Canyon 1 & 2, and has even affected some coal-fired plants, such as Colstrip 3 and 4. Carefully designed, periodic prudence reviews could provide an institutional mechanism to prevent unneeded and environmentally-damaging plants from being built.

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[35]. Robert Abrams, op. cit.

The periodic reviews might also be a way to factor in technological advances made during the course of plant construction. Under the current system, once a plant design is finished, it is difficult to persuade the utility to alter it voluntarily to incorporate advances in pollution control technology. Reviews during the process might provide a way to update the plant plans and apply the best available technology.

If rolling prudence were largely implemented on a state-by-state basis, there could be considerable variety in how the states put it together, much as there are significant differences in how particular states regulate electric utilities today, although most follow the same general model.

Scenario 1 is not without environmental problems. It is not surprising that many of those who advocate it, such as AEP, managed to thrive during the lean years of the late 1970s and early 1980s. They did it by eschewing construction where possible and by keeping their existing plants on line. In AEP's case, many of those existing plants are the oldest, dirtiest coal-burning facilities in the Midwest that are the target of acid rain cleanup proposals.

So the down side to the status quo, from an environmental standpoint, is represented by those older coal-fired plants. For example, Cleveland Electric Illuminating's Eastlake plant as a state emission limit of 5.64 pounds per million Btu and the Avon plant has a 4.65 pound limit, versus the new source performance standard of 1.2 pounds. Other older plants around the country have even higher emissions limits under State Implementation Plans.[36]

The 1970 Clean Air Act (as amended in 1977) was premised on the belief that plants would largely be scrapped after their 30-year book lifetime. Consequently, the act relies on the new source performance standards for its regulatory bite, rather than on pressing for improved environmental performance of existing plants.

Unfortunately, the economic landscape in the years since Congress passed the Clean Air Act has favored keeping existing plants on line and avoiding building new ones. This was driven partly by the costs of pollution control on new plants, but more directly by unusually high interest rates of the 1970s, coupled with declining and unpredictable load growth. Powerplant life-extension and geriatric programs have become a major focus of savvy utilities, and some experts believe that it may be possible to keep plants in service almost indefinitely.[37] Under the Clean

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[36] Figures from Centerior Energy environmental department, interview on Apirl 18, 1988.

[37] "Longer Life for Fossil Fuel Plants," EPRI Journal, July/August 1987, pp. 21-27.

Air Act, if the cost of a life extension program exceeds 50 percent of a "comparable new facility," the plant may be subject to NSPS. According to the Electric Power Research Institute, "This regulation has not yet been tested, and utilities are unsure whether the 50 percent trigger refers only to one-time capital expenditure or to aggregated refurbishment costs over several years."[38]

The status quo offers a strong incentive for utilities to keep the oldest, and usually dirtiest, plants on line as long as possible. In extending the life of the existing plants, the utility avoids siting disputes, heavy capital requirements, and the Damoclean sword of prudency reviews and major disallowances. By contrast, some of the other scenarios might encourage utilities to close the facilities if they can get power cheaper from QFs or independent producers, can raise capital relatively inexpensively, or can avoid the need for prudency reviews and rate basing entirely by building a deregulated plant.

Scenario 2: Expanding Transmission Access in the Existing Institutional Structure."

This scenario basically opens up electric utility transmission lines to bulk power sellers and buyers. Under this scenario, in OTA's words, "Utilities and large retail customers can petition FERC for mandatory wheeling orders to nonlocal generators based on a new public interest standard."

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[38]. Ibid. p. 26. Also, the plant could be subject to NSPS if the emission rate of any of the criteria pollutants is increased as a result of the life extension program.

Just what that "public interest standard" would be is an important item, because it may be possible to build environmental elements and concepts into the standard. For example, it might further environmental goals to wheel in power from remote sites to avoid burning coal or oil in an urban enviornment. In this regard, it is important to note that neither Scenario 1 nor Scenario 2 mention the role that the regional power pools and the National Electric Reliability Council play in transmission planning, an important omission. The pools and NERC function together to advance at least quasi-public values, in that they were put together after the giant 1965 East Coast blackout, in an attempt to prevent future mishaps of that sort. They are, of course, creations of the utility industry and along, and share its perspective on the public interest. Should access to transmission expand beyond the traditional electric utilities, using some sort of public interest test, then the role of both the pools and NERC might be broadened, with an explicitly "public interest" mandate, and public participation beyond the utility industry itself.

Presumably, the result of Scenario 2 would be greater use of transmission, particularly large, unconventional exchanges that would be governed by contract provisions.[39] As a result, utilities would have to plan for third-party transmission in their system planning for their power lines. The result likely would be plans for more transmission lines, with concomitant disputes. Some utilities might see transmission as a new business opportunity and build transmission marketing into their plans.

From an environmental perspective, this scenario could have some favorable and some troubling consequences. On the positive side, greater wheeling could lead to construction of fewer baseload plants and a more flexible electric supply system, better able to to accommodate advanced renewable technologies such as photovoltaics.[40] Greater wheeling and a full national grid could avoid situations such as today's power surplus in the South and Midwest while New England faces potential power shortages.[41] But if expanding transmission access is successful, presumably more transmission capacity will be constructed. As noted earlier in this paper, siting, building, and operating electricity transmission has both well-understood and frontier environmental problems ranging from land use to public health issues associated with low frequency fields.

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[39]. This sort of access to transmission could also stimulate the development of a futures market for electricity. Some of the more exotic OTA scenarios might also have this result.

[40]. A fully-connected grid could act like a storage system for sun-generated power, wheeling power west to east with the progress of the sun, helping to overcome one of the obstacles to photovoltaics. In mid-summer, there are only about four hours a night when the entire continental U.S. is dark.

[41]. For the conventional wisdom on New England's electric needs, see New Engalnd Governors Conference, "A Plan for Meeting New England's Electric Needs, Delcember 1986. For a powerful critique of that view, see New England Energy Policy Council, "Power to Spare: A Plan for Increasing New England's Competitiveness Through Energy Efficiency," July 1987.

Access to transmission might also encourage unneeded plant construction, both by IPPs and QFs. If electric utilities see selling transmission services as a business opportunity, rival utilities might get into price wars attempting to lure generators into their grid. That could lead to construction of plants beyond what would occur simply to supply the PURPA market if transmission continued to be closely guarded.

Presumably, most of those plants would be gas-fired combustion turbines, with perhaps some combined-cycle generation as well (although Case Study 2: Bidding in Massachusetts: a Glimpse of the Future?,[42] somewhat belies this). While natural gas is the cleanest-burning fossil fuel, it is not entirely devoid of pollutants. In non-attainment areas, increased generation could lead to further tension and disputes over pollution offsets and lowest achievable emission rates (LAER). In attainment areas, increased generation would consume some of the PSD increments available for other kinds of development.

Greater access to transmission could also widen the opportunities for trash-to-energy projects. A shortage of suitable land disposal sites, and PURPA currently encourage these plants,[43] and greater access to transmission and hence a broader market for the power, could stimulate them even more. That could lead to even greater contention over waste-to-energy projects at the local and national level.[44]

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[42]. Discussed later in this paper, pp. 53-60.

Greater access to transmission could also slow individual utility conservation and load management programs. Greater transmission access would complicate the analysis that goes into conservation and load management planning. It might become necessary to create regional conservation and load management institutions, such as the power pools and NERC, to match conservation and load management planning with regional transmission and generation planning. This is what has happened in the Pacific Northwest, as a result of the 1981 Northwest Power

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[43] NEESPLAN II, the New England Electric System's comprehensive business plan for the next 15 years, adopted in April 1985, foresees adding 180 megawatts of generating capacity from trash plants by the year 2000, out of a total projection of 500 megawatts coming from "alternate energy." NEESPLAN II also projects 70 megawatts from hydro, 175 from cogeneration, and 75 from miscellaneous sources such as solar and wind. At the time of the plan, NEES was already negotiating contracts from more than 85 megawatts of trash-to-energy in its service territory. See NEESPLAN II, pp. 39-40.

[44] See Neil Seidman, "Garbage In, Garbage Out," Not Man Apart, November-December 1986, pp. 10-11, for an environmental critique of mass burn projects. The Institute for Local Self Reliance has a study of transmission and waste-to-energy projects currently underway.

Planning Act.

Scenario 3: Competition for New Bulk Power Supplies.

This scenario is basically the Keystone and FERC Hesse proposal for all-source competitive bidding for generation. As OTA says, "Scenario 3 creates a two-tiered bulk power supply system: new power supplies under a minimally regulated, 'workably-competitive' market; and existing power generation remaining under current state-federal scheme of regulated entry and pricing. The electric power supply industry will gradually evolve to an all competitive generating sector as existing plants are replaced."

From an environmental standpoint, there is probably more known about this scenario than some of the others, because more thought and effort has gone into it, at both the federal and state level. At least three states[45] have either implemented bidding systems or are in the processing of implementing them, and FERC has issued a notice of proposed rulemaking on bidding for power. An environmental report done for FERC by Oak Ridge National Laboratory identified potentially significant enviromental impacts from the agency's proposed bidding regime, particularly increased use of coal in four states, New York, New

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[45] Maine, Massachusetts, and New York.

Jersey, Virginia, and California.[46] As a result, the FERC will perform a nationwide Environmental Impact Statement as part of its rulemaking, which should shed even more light on the environmental consequences of this scenario.

The scenario offers some potential environmental benefits, chiefly the prospect of more rapid replacement of the older plants with new plants, which are likely to be less polluting. The scenario implicitly assumes that "new" power will eventually drive out "old" because new, "competitively-priced" generation will be cheaper and because old plants will be phased out on some actuarial basis. But if the guaranteed rate of return to the old plants, particularly those that are fully depreciated, exceeds the return on investment available in the competitive market, those assumptions may not hold, and old plants may continue to be a problem.

One environmental issue will be whether and how to treat plant geriatric work in the context of bidding. If a utility is required to bid the added supply associated with a particularly life extension project, it starts with an asset owned by the ratepayers. Even if fully depreciated, the plant would still have a market value. If the market value of the plant isn't factored into the bid price, the utility could reap a windfall profit from the life extension, a further incentive to keep old plants on line. This is similar to the problem posed by a bidding scheme that allows a utility to spin off its existing plant into a deregulated subsidiary and then bid the power from that plant against new construction in the power auction. In both cases, it is necessary to factor in the value of the existing asset in order to avoid subsidizing older, presumably dirtier, plants.

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[46]. "Environmental Report: Regulations Governing Bidding Programs (Docket No. RM88-5-000) and Regulations Governing Independent Power Producers (Docket No. RM88-4-000)," Oak Ridge National Laboratory, March 1988.

Two other environmental issues are particularly pertinent to the concepts of all source bidding to supply utilities with power. The first is how to factor environmental considerations into the bidding process, and the second is how to square the bidding schemes, a supply-side issue, with conservation and load management, demand-side issues. The second issue may prove to be the most difficult to deal with, although not insurmountable.

In the states that have addressed the bidding schemes so far, environmental issues generally have been treated as "non-price" factors.[47] Other non-price factors include such things as reliability, dispatchability, and fuel diversity. The difficulty with the non-price factors is that they introduce an element of subjectivity to the selection of the winning bidder, and take away from the auction aspects of the bidding process. That means there will continue to be a need for regulatory review to make sure that the subjective judgments of the utility don't adversely bias the decisions. It is also possible that the non-price factors will be given less emphasis than the more easily quantifiable price elements in the bids.

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[47]. See testimony of Robert J. Keegan, Commissioner, Massachusetts Department of Public Utilities, before the Senate Energy and Natural Resources Committee, Feb. 4, 1988, p. 8.

In cases where there is a larger policy issue -- such as, for some, fuel diversity -- the bidding process might have to be altered somewhat to reflect this. In New York, for example, Long Lake Energy Company, a hydro developer, suggested that, in view of the public policy in favor of developing renewable sources of energy, the state be required to have separate requests for proposal for renewable projects during the bidding. Otherwise, the company said, a capital-intensive project such as hydro might not be competitive on a price-only basis.[48] Long Lakes may have raised an important issue, but it is important to note that "public policy" exemptions could be the beginning of a very slippery slope where one person's public policy issue is another's pork barrel.

It is important in establishing a bidding scheme to assure that all the players -- utilities, IPPs, and QFs -- are required to meet the same environmental standards, and that those standards also be the highest. In its brief to the New York

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[48] ALJ Frank S. Robinson, Case 29409-Recommended Decision on Bidding, Avoided Cost Bidding, and Open Wheeling, p. 65.

Public Service Commission on that state's bidding rulemaking, Orange & Rockland Utilities argued that "to hold utilities to higher environmental standards would provide IPPs with an unfair and possibly deceptive economic advantage: customers could be receiving an ostensible benefit in their utility bills, with a hidden cost to the state's environment."[49]

Building environmental concerns into the bidding process as a subjective factor at least provides a conceptual way to make sure that awards are environmentally sound. But building in conservation and load management is a far more problematic issue. So far, both New York, Massachusetts, and the FERC have ducked the issue.

In New York, ALJ Robinson simply ruled that demand side management not be included in the bidding process,[50] although the PSC staff had proposed "negawatt" bidding, in which a purveyor of conservation and load management could bid measures to reduce the utility's consumption by the proposed supply increment. Rejecting the concept of negawatt bidding, Robinson argued that the equivalence of demand reduction and supply addition "is imperfect....One can scarcely envision a utility making massive payments to a host of negawatt bidders with respect to sales that are thusly rendered into non-sales, diminishing the utility's base of revenues from which to make such payments."[51]

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[49]. Robinson, op. cit., p. 66.

[50]. Robinson, op. cit., p. 53.

However, there are ways to perfect the equivalence, according to Maine Public Utilities Commissioner David Moskovitz. He would tie a utility's rate of return to relative reductions in the average bills paid by residential customers, and to reductions in electricity use per square foot by commerical customers. Thus, the lost revenues from conservation which New York's Robinson noted would be offset by higher returns on the remaining business.[52]

In Massachusetts, the commonwealth did not include it in the first round of bidding, but has an inquiry underway that, among other things, examines how to include conservation and load management in the bidding process.[53] Boston Edison officials believe that it is possible to include negawatt bidding in the commonwealth's bidding plan.[54]

The FERC's proposed rule on bidding under PURPA does not provide for bidding of conservation and load management. Economist Paul Joskow of the Massachusetts Institute of

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[51]. Ibid. pp. 51-53.

[52]. Aviva Freudmann, "Moskovitz's Modest Proposal: Reward Utilities for Reducing Customers' Bills," Energy Daily, April 15, 1988, p. 1.

[53]. Interview with Henry Yoshimura, Massachusetts Department of Public Utilities, 12 January 1988.

[54]. Interview with John Whippen, Boston Edison Co., 21 January 1988.

Technology has argued that FERC is correct to avoid the negawatt issue. Including demand-side options in the FERC proposal, Joskow told a congressional subcommittee, "could result in higher electricity rates, inequitable electricity rates, windfall profits for some conservation suppliers, and incentives for inefficient conservation investments." But Ralph Cavanagh of the Natural Resources Defense Council told the same committee that omitting demand side options from the rulemaking "would be to exclude from power supply competitions the least expensive resources available to modern electricity systems."[55]

Despite the objections, the negawatt concept is a powerful idea for stimulating energy conservation in a bidding regime. More analytic work, and perhaps some practical experiments, are needed to test whether the barriers that critics raise are real or fiction. Some suggest that negawatt bidding can work by targeting specific loads for reductions, such as motor efficiency, lighting, or buildings.[56]

Scenario 4: All Source Competition for All Bulk Power Supplies with Generation Segregated from Transmission and Distribution Services.

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[55] Dennis Wamsted, "Negawatts or Negafood? A Demand-Side Dichotomy," Energy Daily, April 4, 1988, p. 1.

[56] Whippen, op. cit.

This scenario extends the concepts of Scenario 3 to their logical conclusion, the dis-integration of the heretofore vertically-integrated electric utility. The result is an industry that looks similar to the natural gas industry. As OTA describes this scenario: "Local distribution companies would be primarily responsible for securing adequate power supplies from competing suppliers. Transmission divisions or subsidiary companies would provide wheeling services for utilities under regulated rate schedules and could also act as power brokers linking local distribution companies with power suppliers. Distribution companies could obtain mandatory transmission orders from FERC on a public interest standard. There would be no mandatory wheeling for retail customers."

Both Scenario 4 and Scenario 5 are considerably further from the status quo than any of the predecessors. Consequently, trying to divine their environmental impacts is a speculative enterprise at best.

Nevertheless, several environmental questions present themselves with this full-fledged revolution in the electric utility industry. They are: the older plant problem, how to build in environmental analysis, and the problem of demand side management.

Scenario 4 could present the most powerful incentives yet to continue using older, dirtier plants. The problem is identical to that described in Scenario 3 with regard to whether life extension projects can bid to supply generation on the same basis as IPPs and QFS. Scenario 4 answers that question and the answer is "yes."

In that circumstance, utilities will doubtless argue that since their older plants are fully (or more fully) depreciated, they are the low-cost bidders, ignoring the market value that the plant possesses. The result is a powerful subsidy for the fully-amortized plant, even if a considerable amount is spent in life-extension. This flies in the face of long-standing environmental goals, contained in statutes such as the Clean Air Act and the Clean Water Act, of replacing aging, more polluting plants with new, less polluting industrial plants.

How to solve this problem? Clearly, regulators must structure the rules so that the market value of the existing plant and equipment gets recognized in the free-market price of power from that plant. After all, one can make a powerful argument that it is the public, in the form of the ratepayers, who own the plant, since they paid for it.

One way to deal with this problem would be to force the non-deregulated generating spinoff to bid in a free auction against other generators for ownership of the plant. When a utility spins off a generating company, the utility would continue to own the generating asset, and then sell it to the highest bidder.

One wrinkle on that proposal, made by Long Lake in the New York proceeding, would credit or debit the utility's rate base for any difference between the net book value of the asset and its sale price. The new owner would do the geriatric work and use the refurbished unit to enter the market.[57]

Another environmental obstacle this scenario presents is the familiar one of how to factor environmental analysis into the process. Again, this problem bears on the larger problem of how to get the older plants retired. If all plants are deregulated, those that have older, less sophisticated pollution control devices likely will have a cost advantage in bidding. A new plant, for example, would have to obtain site approval and a host of permits that would not burden the exiting plant.

Additionally, a new plant sited in a non-attainment area would have to go over the costly LAER (lowest achievable emission rate) hurdle, obtain pollution offsets, and the like. In an attainment area, the new plant would have to go through the PSD process. An existing plant competing against those new plants could avoid any of those costs, as well as the high capital costs of scrubbers, bag houses, precipitators, and the like. It will require considerable regulatory ingenuity to figure out how to put the existing plant and new plants on an environmentally-level playing field in this scenario.

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[57]. Robinson, op. cit., p. 55.

Finally, there is the conundrum of how to carry on demand side management in an economic environment that is almost completely supply side (we will go the rest of the way with Scenario 5). In a non-integrated market, with generation separated from transmission and distribution, it is not very clear just who will worry about conservation and reducing demand. The distribution companies or Discos will be less concerned, because they no longer face the risks of construction which have driven much industry concern about demand management. Discos will make money only if they sell power, not by saving. If the equivalence between demand reduction and supply addition is imperfect in Scenario 3, it is even less so in Scenario 4. The scenario would also reduce pressure on regulators to push for conservation and demand management, because they won't face the need to make ratebase decisions, with possible rate shock as a result. Clearly, the interest of the genco will be to generate and sell megawatts.

Scenario 5: Common Carrier Transmission Services in a Disaggregated, Market-Oriented Electric Power Industry.

This final OTA scenario completes the journey to deregulation begun in Scenario 1. All generation would be deregulated, with federal or state rate regulation of transmission, as a common carrier, and state regulation of distribution. Transmission is done by separate transmission firms, acting as common carriers and charging tariff rates, presumably set by the FERC if the transaction crosses state boundaries and enters into interstate commerce. Wholesale and retail customers, gencos, IPPs, and QFs would all have guaranteed access to transmission at a known price. (In practical fact, the terms IPP and QF would no longer have any meaning. All generators are created equal in this scenario.)

In addition to the environmental issues raised with regard to Scenario 4, this scenario has some unique environmental problem areas. The knotty issue of conservation and load management becomes even more intractable in a conventional sense. With transcos now in the market, making their money from selling transportation services, another force has been removed from the conservation and load management equation and added to the supply ledger. Now only the lowly, regulated disco -- probably serving a captive and bypassed residential and small commercial market -- will have any incentive to push demand side measures. And as long as the disco can buy power cheap enough to make a reasonable rate of return on sales, all incentive for conservation and load management disappears.

Scenario 5 also raises the specter of reduced maintenance of power generating equipment. In the rush to compete, particularly if the competition seriously drives down prices and profit margins, generating companies may decided to cut costs by skimping on maintenance. This can have disastrous environmental and health consequences. In this regard, the electric utility industry could come to resemble the deregulated U.S. airline industry, where the accident rate is soaring,[58] perhaps as a result of cost-driven cutbacks in maintenance.

This issue is not present in prior scenarios, because in each case, some strong institutional entity remains with a vested interest in reliability and maintenance. Even in Scenario 4, the integrated transmission-distribution company has a need for high reliability standards.

But in Scenario 5, the only entity with an overriding interest in reliability appears to be the distribution company. For both the genco and the transco, reliability becomes solely an economic issue. If it makes more economic sense to walk away from a market than to continue to sell to it (as a result, for example, of a poorly structured fuel supply contract or a contract for transmission services that turns out to be uneconomic), the genco probably will walk. If the transco has an obligation to provide transmission service, the company might meet that obligation in the cheapest and most grudging fashion. Potentially, this could recreate the circumstances of the railroad industry prior to the 4R Act and the Staggers Rail Act, where rail maintenance was so bad the industry created a new term, "standing derailment," to describe the phenomenon of rail cars that fell over while standing still.

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[58]. Laura Parker, "Airline Accident Rate is Highest in 13 Years," Washington Post, December ?, 1987.

There also is fear is that the disco is a weak sister, bypassed by its biggest customers and left serving only a market that is economically fragmented but politically very powerful (i.e., a market that use its political power to keep its rates low). In those circumstances, the disco may not have enough clout to insist that its suppliers maintain their plants even under adverse economic conditions.

Finally, the sort of industry structure envisioned in Scenario 5 should result in a construction boom for new transmission. Given the ferocity of local siting battles in the past, the result could well be political gridlock.

Going further, it seems clear that Scenario 5 can only come to pass if a way is found to site, construct, and operate power lines with a minimum of disruption and delay. Given the siting issues, which are being addressed for OTA in another report, and the health issues, also addressed in another report, believing that this scenario can ever happen requires considerable credulity.

V. CASE STUDIES

Case studies in two particular areas can serve to illuminate some of the issues raised in the discussion of the scenarios. Thus, they serve as a sort of reality check on what may be pure speculation about the scenarios.

In the first case study, the focus is transmission, specifically a series of tangled, emotional, and expensive disputes about power line siting. It serves to illustrate the passion and difficulties that accompany the environmental issues surrounding where to build power transmission facilities. Until the kinds of issues that led to the difficulties in the cases sited are resolved, it will be difficult indeed to make a transition to a future electric utility industry that requires considerably increased transmission.

The second case study looks at the experience of the Commonwealth of Massachusetts in implementing competitive bidding for new supply under the terms of PURPA. It should help illuminate some of the issues that will face other states if they wish to implement bidding schemes, and should point to some areas at the FERC may want to deal with as it responds to comments on its proposed rulemakings.

1. The Transmission Quagmire: The New York Power Lines Project, Colstrip, Coal Creek, and Klein Independent School District.

In 1973, the New York Power Authority applied to the state Public Service Commission for a Certificate of Environmental

Compatibility and Public Need for a 765 kV transmission line from the Canadian border near Massena to Utica. The total distance is about 155 miles. The certificate from the PSC is a one-stop permit. Once granted, it eliminates the need for any local or any further state permits.

The next year, Rochester Gas and Electric and Niagara Mohawk Power Corp. applied for a certificate for a second 765 kV line, this one running 66 miles from Rochester to Oswego.[59]

When the required public hearings began, it became clear that this would not be a routine siting decision. The public was avid to testify, and raised issues related to audible noise, land use, and, most troubling, biological effects. The administrative law judges in the two cases, trying to avoid duplicative testimony, ordered a common set of hearings for the two power lines.

The hearings on the common issues related to the two power lines took four years, heard 31 expert witnesses, and produced more than 14,000 pages of testimony. Most of that testimony concerned the potential for biological effects from electric and magnetic fields.

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[59] For accounts of the New York case, see Daniel A. Driscoll, "Standard-setting in the United States: A View from New York," paper presented at the International Utility Symposium on Health Effects of Electric and Magnetic Fields, September 16-19, 1986. Also, "EMF: The Debate on Health Effects," EPRI Journal, October/November 1987, pp. 4-15.

A bombshell in the hearings came when information surfaced of Soviet studies done 10 years earlier. The Soviets were investigating symptoms of appetite loss, headaches, fatigue, and insomnia on the part of switchyard workers. The Soviet research concluded that there are biological effects caused by low frequency fields.

The Public Service Commission ruled that in face of the Soviet studies, it had "no alternative but to presume that a biological effect is hazardous until it is proven otherwise." The PSC said that doubts of the hazardous nature of the biological effect can influence the degree of caution that is required, but that it can't be ignored simply on the grounds that it hasn't been proven a menace.

The PSC eventually approved the two 765 kV lines in 1978, but with regulatory constraints. The commission ruled that residences could not be permitted within 175 feet of the centerline of the Power Authority's 765 kV line, limiting residential electric field exposure to less than 1.6 kV/m. According to Driscoll, the effect of this is that the field from the 765 kV line is not greater than that produced by 345kV lines at the edges of their rights-of-way.

"In this way," Driscoll said, ""the commission assured that the risks, if any, of long-term exposure to transmission line electric fields would be no greater than those, which society implicitly accepts, of long-term exposure to the 345 kV lines operating throughout the state."[60]

The PSC also ordered a $5 million research program, the New York State Power Lines Project, to investigate the potential health hazards of power lines. The commission then pegged its restrictions on the 765 kV lines to the findings of the project. "In effect," said Driscoll, "the Commission declared a moratorium on higher fields until the results of the New York State Power Lines Project could be evaluated."[61]

The Power Lines Project issued its final report in July, 1987. Earlier in the year, in February, researchers David Savitz, Howard Wachtel, and Frank Barnes released a study, sponsored by the New York project, finding a modest statistical correlation between childhood cancers and magnetic fields. According to Savitz, "There is no solid evidence that people should be worried, even if they live under a power line. The bottom line is that the evidence falls short of proving that electric or magnetic fields are a health hazard. On the other hand, questions have been raised that haven't been answered. So for a public health perspective, there is a reason for concern."[62]

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[60] Ibid., p. 3.

[61] Ibid.

[62] Quoted in a September 4, 1987 EPRI memo to its Advisory Council members, p. 2.

The Savitz research buttresses a 1979 study by Nancy Wertheimer and Ed Leeper, and is causing considerable anxiety in the utility industry. EPRI has formed a 15-member panel of experts, headed by Gilbert Ommen, dean of the School of Public Health at the University of Washington, to review the EPRI research program on health effects in light of the emerging evidence that fields have biological effects.[63]

The emerging evidence on health effects is likely to make transmission line disputes all the more contentious and difficult. And the New York dispute was far from the most difficult of those that have been waged in the U.S. in recent years.

Colstrip

In Montana, for example, a dispute over building two 700-megawatt plants in the eastern coal fields of the state eventually turned into a nasty dispute over transmission. The project, announced in 1971 as a joint venture involving Montana Power Co., Puget Sound Power and Light, Portland General Electric, the Washington Water Power Co.,a and Pacific Power & Light, planned the two new Colstrip Units (units 3 and 4), and two new parallel 500kV lines from Colstrip to the Bonneville

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[63]. Ibid.

Power Administration system in western Montana.[64]

The Colstrip project, of course, has a solid place in modern electric utility history for a variety of reasons. The plants, which ultimately turned out to be largely unnecessary, led to the formation of a powerful environmental movement in the West, the Western Organization of Resource Councils. The Colstrip dispute also provided an important chapter in the story of the rise of prudence reviews.

But Colstrip also made its mark in the annals of transmission disputes. Eventually the power lines were built, 12 to 15 years after first announced. The project, which crossed public and private land and Indian land, required a full-scale, federal Environmental Impact Statement, seemingly endless hearings, and an enormous record that fills several feet of bookshelf. For the most part, the dispute centered on health effects, and the public evinced considerable skepticism about claims that power lines are safe. In the words of a BPA official, "It was very difficult to gain the confidence of the public relative to the biological effects issue. I think many of them automatically distrusted any entity of the Federal Government telling them that something was safe. I believe this is primarily based upon other situations involving hazardous waste dumps, the

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[64] See George Eskridge, "Colstrip Transmission Project," paper presented at the International Utility Symposium on Health Effects of Electric and Magnetic Fields, September 16-19, 1986.

Love Canal issue, and other areas of controversy over health issues involving the Federal Government."[65]

BPA's difficulties with the Colstrip line led Montana to adopt an innovative approach to power line regulation, which is done through the state's Major Facility Siting Act. Montana hired Dr. Asher Sheppard, one of the leading researchers in the field, to help the state set rules for exposure and mounted an administrative rulemaking process involving extensive hearings. As a result of Sheppard's recommendations and the public record, the state adopted a conservative standard for electric fields, tougher even than New York's. The state prohibits the electric field at the edge of right-of-way for new facilities from exceeding 1 kV/m measured one meter above the ground in residential or subdivided areas. The field at road crossings under the line cannot exceed 7 kV/m at one meter.[66]

An interesting aspect of the Montana rules is that affected landowners can waive the 1 kV/m standard across their property. Subsequent landowners have to live with the previous landowner's waiver. According to a Montana official, "The state feels that it is appropriate for landowners to participate in making decisions that affect their personal land-use objectives and possibly their health. Science has not provided any definitive answer to the question of the risk associated with living or working very close to a major energy transmission facility. Montana's standard permits affected landowners to judge what is an acceptable risk for them."[67]

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[65] Ibid. p. 9.

[66] Van Jamison, "Regulating Emissions in Montana," paper presented at the International Utility Symposium of Health Effects of Electric and Magnetic Fields," September 16-19, 1986.

Coal Creek

The processes in both New York and Montana were orderly compared to what happened in Minnesota when two cooperatives, Cooperative Power Association and United Power Association, announced a two-unit, 1,100 megawatt mine-mouth lignite-burning plant near Underwood, N.D., along with a 436-mile ±400kV high-voltage, direct-current line from the state to west of Minneapolis, and two ac lines to move the power into the existing transmission system.

The problem was the 177-mile section of the HVDC line in Minnesota, which crossed eight counties and required easements in 476 parcels of land. Licensing required 15 months and three separate state permits. Each permit required a full set of hearings, meetings, and deliberations by citizen committees. The project also had to prepared a full-scale Environmental Impact Statement. The Coal Creek HVDC line got its final permit in June

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[67] Ibid., p.4.

1976 and construction began in October 1977.[68]

Opponents of the project, drawing on the Russian research and the New York controversy, focused on the health issue. Before issuing the final permits, the Minnesota Environmental Quality Board commissioned several studies of health effects, culminating in a report by the Minnesota Department of Health finding no health problems. But as a United Power Association official said, "The MDH report did nothing to lessen the controversy because: in 1977, opposition to the line was in the ascendancy; the report was prepared without public involvement and therefore was viewed as suspect; and the MEQB did not place any emphasis on the report's findings." According to critics, the state's heavy-handed approach to the issue may well have exacerbated the dispute and energized its opponents.[69]

Despite the MDH report and MEQB license, controversy over the line escalated, particularly in two counties, resulting in violence and vandalism during the construction. Through 1983, protestors had toppled a total of 16 steel transmission towers, at a replacement cost of $1.5 million. Replacement power and lost revenue costs exceeded $1.5 million. Opponents destroyed some 9,000 insulators, at a cost of $700,000. Sabotage of construction equipment totaled $300,000 in damages. Extra security costs amounted to about $4.8 million. Total cost of vandalism: more than $8.5 million.[70]

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[68] Dan McConnon, "Health Effects from HVDC Transmission Lines: Resolution of the Minnesota Controversy," paper presented at the International Utility Symposium on Health Effects of Electric and Magnetic Fields, September 16-19, 1986.

[69] For a harsh appraisal of the project and the state actions, see Wendell G. Bradley, "A Preliminary Cost Appraisal of the Coal Creek Project," in Lines Across the Land, Environmental Policy Institute, 1979, pp. 474-486.

Klein Independent School District

In Texas, courts did more damage than vandals to a power line project, fining Houston Lighting & Power $25 million in punitive damages in 1985, and forcing the utility to move an already-constructed power line. The case is still in litigation, as HL&P attempts to overturn the fine.[71]

In 1980, the utility wanted a new 345kV line, and proceeded to condemn property and build the facility, with no opposition. Part of the line passed over land owned by the Klein Independent School District.

After the line was already in place, the school district built a new school under the power line. At the same time, the school district sued the utility, arguing that the condemnation proceeding was flawed.

In 1985, the case went to trial before a six-person jury. At that point, the school district first broached the health effects issue, charging that HL&P had "grossly abused its discretion" by putting a health risk on school property. The jury heard six expert witnesses on the health effects issue, four for the school district and two from the utility.

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[70] McConnon, op. cit.

[71] "Evolution of an Issue," EPRI Journal, OCtober/November 1987, pp. 10-11.

The jury found heavily for the school district. The jury awarded the district $104,000 plus interest in actual damages, $25 million in punitive damages, and told the utility to restrict use of the line to emergencies outside of school hours, pending appeal.

Ultimately, HL&P mooted most of the issues, by moving a 2.5 mile segment of the line around the school property. But in the meantime, the utility lost the use of the line for two years. The utility continues to try to overturn the punitive award.

"As the HL&P case reveals," commented EPRI Journal, "the field effects issue is far from being resolved. Investigators have not yet been able to satisfactorily address the key uncertainties, and the legal debates continue in the absence of sound scientific evidence."

2. Bidding in Massachusetts: A Glimpse of the Future?

Massachusetts appears to have gone farther than any other state in implementing a bidding scheme for allocating generation under PURPA. The commonwealth issued its first set of regulations in late 1986 and the first contracts under the bidding scheme should be formally awarded soon. The state and its utilities are now working on a second round of bidding, with somewhat changed circumstances.[72]

The bidding process begins with the supply and demand files for each utility that are supplied to the state's Facility Siting Council. On the basis of that plan, the utility forecasts what its next supply addition will be. If, for example, the utility were to conclude that it's next piece of generation would be a 200-megawatt combined-cycle facility, then the utility would attempt to solicit 200 megawatts of supply from QFs, to avoid that new facility.

The Massachusetts regulations stipulate how to calculate the costs of the new generating capacity, including system fuel costs and capital costs. That determination, which is the equivalent to the avoided cost, becomes the ceiling price for the bidding process. In other words, the avoided cost becomes the maximum that the utility will pay to QFs.

The Massachusetts program works with a standard contract, developed by the DPU, against which the suppliers are to bid. The utility can include "non-price" elements in its solicitation and bid-evaluation process. This is where the utility can build in environmental constraints, or other issues such as reliability, dispatchability, fuel diversity, or the like. The standard contract provides a baseline, but the final contract does allow for negotiation, as long as the DPU is able to exercise oversight.

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[72] Much of this case study is based on interviews with Henry Yoshimura of the Massachusetts Department of Public Utilities, who was the author of most of the bidding regulations, and John Whippen, manager of energy resource planning and forecasting, Boston Edison Co., who is in charge of the project for Boston Edison.

The current bid system does not include provisions for conservation and load management. That thorny issues, along with the issue of how to treat non-QF facilities, is currently the focus of another regulatory proceeding, which is underway at the DPU.

It is important to note that Massachusetts already requires wheeling within the state, on the basis of an open, published tariff. If a QF in the western part of the state wins an award from Boston Edison, state regulations require the intervening utilities to wheel the power, basically as common carriers.

The Experience To Date

So far, Boston Edison Co. is the only utility to have completed the full cycle from the first RFP. The company hopes to have contracts signed soon, for 344 megawatts of power in nine separate projects.

Boston Edison was seeking only 200 megawatts, and got bids for 1,860 megawatts. The levelized ceiling price for the bid was

8.7 cents per kilowatt hour, and the successful bids came in at between 6 and 6.5 cents.

The reason Boston Edison is awarding contracts for 344 megawatts is that the first eight low bidders came in at a total of 144 megawatts, but the ninth bidder offered 200 megawatts. After some negotiations among the parties, Massachusetts DPU concluded that Boston Edison could go forward with the nine bidders.

Massachusetts examined California's experience with its Standard Offer No. 4, where as many as a third of the bidders turned out to be speculative projects that likely never would have been built. In order to prevent that, Massachusetts' regulations require that the QF put up a $15 per kilowatt deposit at the contract signing, as earnest money.

Environmental Issues

From an environmental standpoint, the projects that Boston Edison has selected do not inspire great confidence that bidding will result in a better fuel mix or greater environmental protection than conventional avoided cost determinations.(See list below.)

Project	Size	Technology
FHN Energy (w/Dominion Resources)	200 mw	coal-AFB

Clean Harbors	2.5 mw	hazardous waste
Bellingham	68 mw	gas-combined cycle
NEES-cogen	3.3 mw	combustion turbine
NEES-cogen	3.3 mw	combustion turbine
NEES-cogen	24.5 mw	gas-combined cycle
NEES-cogen	10 mw	gas-combined cycle
Webster Resource	7.4 mw	trash-mass burn
Wheelabrator Energy System	25 mw	construction debris (aka. urban woods)
	344 (total)	

Several things are troubling about the successful bidders for the Boston Edison contracts. First, the 200 megawatt coal-fired facility belies the widely-shared expectation that gas would be the preferred fuel for QFs and IPPs. It is also important to note that the original bid for the 200-megawatt atmospheric fluidized bed facility proposed a site in East Boston, a small, highly-urbanized area. Subsequently, the project developers have decided that perhaps an inner-city site wasn't such a good idea, and have proposed two alternative sites for the project.

Also troubling are the waste-to-energy plants, particularly the Clean Harbors project. That project plans to burn hazardous wastes in a rotary kiln, raise steam, and sell power to Boston Edison. Whether this project will ever be licensed is clearly a legitimate question. The Webster mass burn facility is already running into the predictable siting disputes, which threaten to derail or delay the project.

The Wheelabrator project is one of several "urban woods" schemes to burn construction wastes. Construction wastes would appear to offer a higher-quality fuel stream than the conventional mixed trash. It might also be a cleaner waste stream, although one could postulate some environmental problems with construction trash, particularly with air emissions and ash toxicity from burning lumber treated to resist termites. Another problem could be associated with the amount of gypsum wallboard in the waste stream. Burning gypsum could cause serious sulfur dioxide problems.

There is an interesting irony in the four NEES cogeneration projects. While NEES has been among the utilities that have been pushing the FERC to embark on an all sources bidding scheme,[73] the company has been less enamored of bidding at home, at least as a purchaser of QF power. NEES argued in the Massachusetts proceeding that it could get more power, cheaper by negotiated contract rather than open bidding. The DPU gave the company an exemption from its bidding procedures in return for NEES agreements on more stringent wheeling procedures, and to a provision that the company must demonstrate that it obtains more power for less money by negotiations. Thus DPU and other utility officials were surprised when NEES was a major bidder for the Boston Edison contract.

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[73] Bill Rankin, "FERC Competitive Bidding Plan Splits The Utility Industry," Energy Daily, Sept. 9, 1987, p. 1.

The technological mix that resulted from the first Boston Edison RFP was probably a result of bonus points the company awarded in the non-price section for fuel diversity. "We had established certain objectives we wanted to pursue" in the first RFP, said a Boston Edison official[74]. "That included the promotion of fuel diversity."

Boston Edison plans to revise its RFP over the next few months, to match an updated resource plan. The company expects to file RFP No. 2 with the DPU in March. While the RFP will be "philosophically" the same, it will be less price intensive, and push several non-price issues.

Anticipating regulatory changes[75], Boston Edison likely will push environmental performance by provide target pollutant levels, with a bonus for commitments by bidders to exceed those targets. The RFP, for example, might specify a 1.2 pounds per million Btu standard for SO2 emission, and give a bonus for a commitment to exceed by 110 percent.

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[74]. Whippen, op. cit.

[75]. Massachusetts in 1985 passed an acid rain control law that will require substantial sulfur dioxide emission reductions by 1995. The law requires an average emission rate of all facilities in the state of less than 1.2 pounds of SO2 per million Btu. New England Power, the NEES generating subsidiary, expects that it will have to reduce emissions from its Massachusetts facilities by as much as 46,000 tons per year. New England Power Fact Sheet, "Using Natural Gas at New England Power Company's Brayton Point State to Meet Massachusetts Acid Rain Law Requirements," January 18, 1988.

Boston Edison is also pondering how to build conservation and load management bids into the RFP, probably by targeting specific loads the utility wants to reduce. Utility planners hope to have some version of a negawatt bidding system in place.

Other Massachusetts utilities are not as far down the bidding road as Boston Edison. The DPU has approved the following supply additions, and ceiling prices, for the participating utilities:

Cambridge Electric Light Co.	33 mw	7.33 cents per kwh
Commonwealth Electric	76 mw	6.52 cents per kwh
Eastern Edison	30 mw	6.86 cents per kwh
Fitchberg Gas & Electric	11.7 mw	7.69 cents per kwh
Nantucket Electric[76]	3.6 mw	7.8 cents per kwh
Western Massachusetts Elec.	40 mw	5.8 cents per kwh

Clearly, capacity bidding in Massachusetts has not proceeded far enough yet to make any firm conclusions about how it is working from an environmental standpoint. However, the first

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[76] Nantucket Electric supplies Nantucket Island and is not connected into the Massachusetts grid.

Boston Edison bids have some troubling aspects, because of the unexpected presence of a large coal-fired plant and the proliferation of waste-to-energy projects. The second round of bids, driven by tough new pollution rules, could be better. It will be worth watching what goes on in Massachusetts as a harbinger of what might occur as a result of the FERC bidding initiative.

VI. CONCLUSIONS

Change is a given in the electric utility industry, and most observers would agree on the general direction of that change: toward greater deregulation of generation and away from the traditional pattern of the vertically-integrated electric utility. But as those changes appear, it will be important to keep an eye on the environmental impacts of the changed circumstances and conditions in the industry.

None of the scenarios outlined by OTA are inherently incompatible with national environmental objectives. Nor are any of the scenarios inherently preferable on environmental grounds--at least, given our current level of understanding. However, as each scenario diverges further from the status quo than its predecessor, assessing environmental consequences become increasingly difficult and problematic.

In all cases, environmental analysis must be an integral component of the policy making that will accompany the changes in the electric utility industry. It is neither desirable, nor practical, for advocates of the particular changes in circumstances -- such as freer wheeling or decoupling generation from rate regulation -- to assume that what they propose is environmentally neutral or benign.

It is also important when considering environmental impacts to be mindful of Murphy's Laws and the doctrine of unintended consequences. What can go wrong, will. The planned will not occur as planned, and the unplanned will occur.

OTA WORKING PAPER

ECONOMIC AND PLANNING IMPLICATIONS OF THE FERC NOTICE OF PROPOSED RULEMAKINGS ON INDEPENDENT POWER PRODUCERS: A REVIEW OF DOCUMENTATION

By

The Energy Center
University of Pennsylvania

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INTRODUCTION

The Federal Energy Regulatory Commission (FERC) has released three Notices of Proposed Rules (NOPRs) for comment by concerned parties. These three NOPRs address the issue of a change in structure of the electric power industry and the implications these changes might have for competitors within the industry. The three NOPRs are entitled:

(1) Regulations Governing Independent Power Producers (IPP NOPR)

(2) Regulations Governing Bidding Programs (Bidding NOPR) and

(3) Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities (ADFAC NOPR).

This report evaluates some of the economic implications (for utility planning and operations only) of increased competition in the electric utility sector identified in a review of selected documents submitted to FERC commenting on the proposed rulings (see Table 1). The review also includes arguments made by FERC in the NOPR's, as well as the dissenting opinions of Commissioner Trabandt. (Appendix A includes summary tables of the reviews of the documents)

The report organizes the impact of the proposed rules into two basic categories: impacts on planning and impacts on operations. Under the impacts of planning, some of the possible subcategories are:

- System Reserve Margins
- Construction Lead-times
- Fuel Mix and Technology Choice
- Construction and Financing Costs
- Overall System Reliability
- Siting of Plants

The impacts on operation of utilities include the following subcategories:

- Cost of Coordinating Equipment
- Effect on Economic Dispatch
- Operating Efficiency
- Operating Reliability
- Effect on Transmission Requirements
- Effect on Power Pool Agreements

The University of Pennsylvania evaluation found a wide variety of perpesctives on the possible impacts of the NOPR rules. Generally, the commentors did not provide strong and/or detailed evidence to support their respective views. There does not appear to have been any published rigorous attempt to examine the impacts these will have on operations. Both the FERC NOPR documents and the dissenting opinion by Commissioner Trabandt cite studies which quantitatively assess possible impacts indirectly by analyzing related issues, but the issues addressed here, in many cases, have not been assessed directly.

This report first summarizes the intent of the NOPRs and then assesses the impacts mentioned in the NOPRs and the other documents. In the NOPRs, the commission presents 'benefits' and 'concerns' about the proposals. The summaries included here will be presented in the same format.

TABLE 1: NOPR COMMENTS REVIEWED

1. American Paper Institute, (API)
2. American Public Power Association (APPA)
3. Consumer Federation of America and Environmental Action Foundation (CFA & EA)
4. Cogeneration and Independent Power Coalition of America, Inc. (CIPCA)
5. Edison Electric Institute (EEI)
6. Electricity Consumers Resources Council, Competitive Electric Power Alliance, Council of Industrial Boiler Owners (ELCON, CEPA, & CIBO)
7. Fourty Utilities (40 UTIL)
8. Maryland People's Counsel (MPC)
9. National Association of Regulatory Utility Commissioners (NARUC)
10. National Association of State Utility Consumer Advocates (NASUCA)
11. North American Electric Reliability Council (NERC)
12. National Independent Energy Producers (NIEP)
13. Consumer Owned Systems and National Rural Electric Cooperative Association (NRECA)
14. Public Service Commission of Maryland (PSCOM)
15. State of Maine Public Utilities Commission (SOMPUC)
16. Utility Working Group (UWG)

STREAMLINED REGULATIONS FOR INDEPENDENT POWER PRODUCERS: RATIONALE

The method and rationale proposed by FERC for streamlining regulation applicable to IPPs is described on pages 1 and 2 of the IPP NOPR document:

> The Federal Energy Regulatory Commission (Commission) is proposing to streamline regulation of a class of non-traditional utility suppliers, called independent power producers (IPPs). The proposed regulations would: (1) authorize rates for IPPs to be determined through competitive bidding or rate negotiation subject to a price cap, thereby freeing IPPs from cost-based ratemaking while ensuring rates fall within a zone of reasonableness; (2) authorize IPPs to file rate schedules without having to provide extensive cost support; (3) exempt from cost-related accounting, reporting, and record-keeping requirements; (4) streamline the corporate and financial regulation of IPPs; (5) provide for virtually automatic authorizations to engage in certain corporate activities; (6) revise filing fees; (7) waive annual charges; and (8) adopt an advance certification procedure to qualify as an IPP. By promulgating these regulations the Commission seeks to increase supply options in the wholesale electric energy market and thereby fulfill its statutory responsibilities under the Federal Power Act (FPA) and Public Utility Regulatory Policies Act of 1978 (PURPA).

FERC proposed the streamlined regulations because of problems in the electric utility industry. Several problems have plagued the industry since 1970. First, load growth was lower than predicted, and the utilities were caught with excess capacity. In addition some capital expenditures were granted less than full recovery by regulators. Thus, FERC asserts, many utilities have adopted a risk minimization strategy towards building new capacity.

FERC suggests that the result of this risk averse strategy by the utilities may be the building of less capital-intensive and less technologically innovative capacity. This will hinder development of new technologies and lead to inadequate supplies of electricity.

Finally, FERC notes that predictions of the needed capacity in the next decade vary widely. This factor in combination with the risk minimization factor lead to uncertainty about future supply and capacity. Due to the uncertainty in supply, FERC has proposed streamlined regulations to promote additional sources of supply through competition (IPP NOPR, P. 10-18). FERC is concerned that utilities may be unprepared should a supply shortage occur in the 1990's. The commission believes that current regulations inhibit investments and that there is a need to create an environment which encourages investments to ensure these investments will be made in a timely manner.

On the other hand, Commissioner Trabandt and other commenters do not believe that there is sufficient evidence to warrant the NOPRs. While Commissioner Trabandt agrees that the issues of avoided cost and bidding need to be discussed, he disagrees with the need for discussing the generic deregulation of IPPs (Trabandt Dissenting comments P. 3 & P. 10-11).

The disagreement stems from the question of whether new capacity will be needed, and if this capacity would be available without the new regulations. The commssion asserts that:

> The recent events...raise serious concerns about the future reliability and cost of electricity obtained exclusively under traditional forms of regulations. If these concerns are realized, there could be serious consequences to the nations economy (IPP NOPR p.17)

To support the opposing view, Commissioner Trabandt refers to sources which state that no additional capacity will be made available from the NOPRs and that adequate capacity will exist:

> Available evidence from all sectors...indicate that those assertions [that new rules are needed for adequate supply of new capacity] are simply false and that needed new capacity, including capacity from IPP's, is being acquired by electric utilities across the nation today under existing regulation. (Trabandt dissent p. 28).

The question of whether there will be adequate supply in the late 1990's is the fundamental concern, and it strikes at the overiding reason FERC has given for providing the NOPR restructuring. The evidence cited by both parties however, is conflicting and there is no clear answer.

FERC also proposed the streamlined regulations because of the burden of cost-of-service regulations on IPPs. The commission believes that this regulation creates disincentives for investment in IPP's. Investment is hindered because innovative technologies are deemed to be riskier than technologies from more traditional sources of supply and because risks often outweigh the gains to the IPP. Cost-of-service regulations were originally aimed at the utilities and was put into place to protect the public from abuses from monopolistic market power. Since it is assumed that IPPs lack significant market and monopolostic power, FERC proposes that the regulatory protection of public interests afforded by cost-of-service regulation is not warranted. (IPP NOPR, P. 22-29).

NEW DEFINITION OF INDEPENDENT POWER PRODUCERS

Until this point, the term Independent Power Producer (IPP) has been used to categorize a group of nontraditional utility suppliers. FERC's initial definition of an IPP is also a broad conceptual definition. FERC further refines its criteria for an

IPP in the IPP NOPR. Definitions which represent the evolution of FERC's IPP criteria are quoted below (IPP NOPR, P. 30-34):

> IPP (CONCEPTUAL):
> "...a generating entity (other than a QF) that is unaffiliated with the franchised utility in the area in which the IPP is selling power and that for other reasons lack significant market power."
>
> MARKET POWER:
> "...the ability to influence the price that customers in a particular area must pay for a product."
>
> SIGNIFICANT MARKET POWER:
> "...the ability to set and maintain a price in excess of the cost of competitively supplied generation."
>
> COST OF COMPETITIVELY SUPPLIED GENERATION:
> "...reflects the minimum cost available to a buyer with substantial supply options."
>
> IPP (NARROW):
> "...the Commission tentatively concludes that a seller is not likely to possess significant market power over a wholesale customer when it sells power from a plant not subject to cost-of-service regulation to a customer that:
>
> (1) is not located in a retail service franchise territory possessed by the seller (or any of its affiliates), and
> (2) is not served by transmission facilities that are essential to the customer and that are controlled by the seller (or any affiliate of the seller).
>
> To implement this 'bright line rule,' the Commission proposes to define two terms: independent power facility (IPF) and independent power producer (IPP). And IPF would be a facility (or portion of a facility) that is not in any utility's wholesale or retail rate base and not otherwise afforded the regulatory assurances of cost recovery under cost-of-service regulation."

This new definition of IPP's is the first part of the proposed rulings made in the NOPRs. These definitions provide the basis for the other major ruling which is related to a bidding process for new generation designed to foster competition for generation of electric power.

REGULATIONS REGARDING BIDDING PROCEDURES

The proposed bidding procedures appear to be the most controversial provision in the NOPRs. Most responses from the commenters address issues raised in the Bidding NOPR. The Bidding NOPR, as well as sections of the other two NOPRs, propose bidding procedure guidelines to determine avoided cost rates. FERC states (Bidding NOPR, P. 12):

> In response to the numerous comments on the implementation of the avoided cost rule, the Commission proposes to adopt new rules that would more accurately establish utilities' avoided costs. To accomplish this, the Commission is issuing two proposed rules. This proposed rule addresses bidding procedures as a means of establishing avoided cost rates. The Commission is also issuing a proposed rule which would refine its regulations on administratively determined avoided cost in Docket No. RM88-6-000.
>
> Under the Commission's proposal, participants in bidding would be provided the opportunity to receive capacity payments as well as energy payments associated with the capacity. Utilities would still be required to offer to purchase electric energy from QFs that were unsuccessful bidders for capacity and QFs that did not participate in the bidding process. These QFs, however, would be entitled only to avoided energy payments which would be determined administratively.

The bidding procedure presented by FERC was initiated because of the perceived problems with determining avoided cost. One such problem that commenters have noted is that the avoided cost determination process is slow and unmanageable (Bidding NOPR, P. 8).

Another problem noted in the documents involve the transaction between utilities and QFs. For instance, many electric utilities complain that avoided cost payments to QFs often exceed the utility's full avoided cost. Many QFs, however, complain that the avoided cost payments they receive from utilities are an underpayment compared to a utility's full avoided cost. In addition, QFs do not believe that in all cases they are adequately being given the chance to compete with alternative utility strategies. Finally, the 'first-come, first-served' approach of QF sales to utilities doesn't always promote sales from the most efficient QFs to the utilities (Bidding NOPR, P. 8-11).

Discrepancies among methods used by utilities to determine avoided cost can hinder the development of IPP's becasue investors do not face a consistent set of avoided costs and it therefore is difficult ot plan. For example, some avoided cost procedures only take into account the utilities' own cost of power production and do not take into account the cost of power from alternative sources. Also multi-state utility operators may have problems determining avoided cost if determination procedures vary between states (Bidding NOPR, P. 8-11).

FERC has proposed the implementation of bidding procedures as a method for limiting problems associated with calculating a utility's avoided cost. FERC states (Bidding NOPR, P. 13-15):

> The Commission believes that a properly implemented bidding system could effectively address many of the problems in implementing the avoided cost rule which were identified in the Commission's conference on PURPA. In particular, the Commission believes that bidding has the potential for eliminating the seemingly endless debates over what alternative sources of supply are truly avoided by the purchasing utility. Avoided cost need not be an administratively determined number, argued over by experts. Instead, avoided cost could be derived simply and directly from the prices offered by competing suppliers in the bidding process. Because bidding provides a systematic mechanism for identifying potential suppliers, it increases the chances that the

> purchasing utility's capacity needs will be supplied from the more efficient sources. In light of these advantages, the Commission proposes to adopt regulations under which state regulatory authorities and nonregulated electric utilities could implement bidding procedures as a means of determining avoided cost.

Through the new definitions of IPPs and the bidding procedures FERC hopes to promote increased competition in the generation of electricity. There is controversy surrounding the expected benefits and costs of the proposed rulings and these are outlined in the following sections. We follow the categories as presented in the Bidding NOPR document prepared by FERC.

"BENEFITS" OUTLINED IN THE NOPRS

Under existing policies, FERC asserts that IPPs development would be hampered and benefits to the utility, consumers and the economy would not be fully realized. Streamlining the regulations would provide a series of benefits to all parties concerned. These outlined in the IPP NOPR are:

New Source of Capacity
Least Cost of Supply
New Technologies
Fuel Mix
Reallocation of Risks
Reduced Distortion of Investment

This section will review these "benefits" and discuss the expected impacts of the NOPRs as seen by FERC, Commissioner Trabandt and the documents submitted by the interest groups listed in table 1.

NEW SOURCES OF CAPACITY

FERC anticipates that IPPs will be a source of new capacity in the future (IPP NOPR, P. 49) which FERC asserts will be needed because of the perceived uncertainty about the future of electric capacity supply. FERC believes capacity from IPPs would be another supply option for utility managers and that IPP capacity might be available more quickly to meet uncertain demand (IPP NOPR, P. 50) with these proposals.

On the other hand, Commissioner Trabandt predicts that there will be no increase in overall capacity under the NOPR proposals even if IPP generation increases (Commissioner Trabandt cites a March 11, 1988 Oak Ridge National Lab Environmental Report; Trabandts Dissent, P. 20 & P. 28) and if there becomes a capacity shortage these proposlas will not alleviate the problem.

LEAST COST OF SUPPLY

FERC, in the Bidding NOPR states that existing facilities which qualify as IPFs for sales by IPPs have the possibility of being low cost suppliers. The existing facilities are presumed to supply electricity at a lower cost because their capital cost may already be sunk and these units may be fully depreciated (IPP NOPR, P. 51). Therefore the total incremental cost may compare favorably with a new central station unit. Also, with competition and the lack of a guaranteed market, IPPs would have strong incentives to minimize construction and operating costs of new facilities.

Commissioner Trabandt believes that construction and financing costs could increase under the NOPRs, due to increased business risk (dissenting comments, P. 39).

In evaluating least-cost supply, one needs to look at some of the components that make up the costs. These include; system planning; construction lead-times; construction and financing costs; and economic dispatch.

With regard to system planning, the arguments rest on whether utilites can incorporate the IPPs into system plans. According to APPA, the imposition of rigid rules will diminish the flexibility which least cost planning allows (APPA does not specifically cite a reason for this impact, P. 2) and will impact the way utilities evaluate expansion plans. NERC and SOMPUC (State of Maine PUC) also claim that the expansion planning will be incomplete because utilities cannot acount for the IPP's in their planning. NERC does say, however, that with proper information and planning this can be solved.

On the other hand CFA&EA (Consumer Federation and Environemntal Action) argue that utilities will be able to adjust to incremental additions of third party power over a considerable period of time because "even if all capacity additions planned for the next ten years were provided by third parties, [these additions] would represent only about 15 percent of total capacity in 1996."

As for the impact on construction lead-times, comments from EEI suggest that there is a potential for longer lead-times if the NOPRs are adopted. EEI believes that the bidding NOPRs would increase uncertainty and therefore would increase the risk of plant completion delays (EEI, Bidding Comment, Appendix B, P. 8).

However, 40 Utilities believe that the use of "package" or "off-the-shelf" plants can shorten lead-times. (40 UTIL, P. 68). APPA stated that the new rules may correct the long lead-time situation which has developed due to "flawed" application of existing technologies (primarily nuclear).

NIEP was the only commenter to directly address the impact of the NOPRs on the construction and financing costs. NIEP states that IPPs will continue to have a capital minimization problem even with the adoption of the NOPRs. NIEP suggests that Wall Street financiers and the structure of competitive bidding will have a greater impact on construction and financing costs than the adoption of the NOPRs (NIEP, P. 12).

The final category addressed is the impact on economic dispatch. EEI and APPA agree that the impact on economic dispatch of the proposed NOPRs will be negative. Both expect economic dispatch to be impaired primarily due to technological problems under the NOPRs (APPA, P. 6 & EEI, Bidding Comments, Appendix B, P. 16) and further. APPA does not provide evidence to support this view however, APPA does cite FERC section 205 & 206 and claims this supports the assertion (APPA, P. 6).

EEI feels that non-utility generators will be inhibited from participating in economic dispatch because of financial difficulties due to uncertain revenues (EEI, Bidding Comments, Appendix B, P. 16). However, according to FERC if the IPPs are the least cost supply, then there should be no problem with economic dispatch from an economic standpoint. CFA supports this point in saying that the empirical record of the performance and dispatchability of IPP plants does not support assertions bu the utility industry about their inferior performance, and therefore, they should be able to participate in economic dispatch (the State of Maine PUC suggests also supports this by saying that QFs would improve economic dispatch and overall costs because they are less expensive by definition).

There are also concerns about increased costs associated with the process of economic dispatch. NERC asserts that there may be additional costs required for control equipment and line improvements. NERC questions whether the cost of these improvements will be justified, but unfortunately does not supply supporting evidence.

There are a number of widely divergent views on the impact of these rules on the least-cost of supply to require a more directed study to detail the possible impacts of the rules.

NEW TECHNOLOGIES

The bidding NOPR states that a benefit of the proposed rule changes will be a demonstration of innovative technologies. The NOPRs note that traditional cost-of-service regulation may inhibit investment in high-risk technologies (IPP NOPR, P. 53-54). There are certain limits inherent in PURPA which may hinder technological improvement. "If a utility attempts some novel technique for producing electricity, and the effort ends in failure, the company can expect a prudence investigation and a possible disallowance of investment costs" (IPP NOPR p. 53-54). This forces utilites into a somewhat risk averse situation, but with streamlining regulations, IPPs may find that the risks of developing new technologies may be tolerable.

Commissioner Trabandt points out that the NOPRs would exclude some types of technology from consideration. This is done by giving state regulatory agencies the ability to exclude subsidized technologies such as nuclear (IPP NOPR, Appendix, P. 33). He says also that the rules will favor smaller intermediate load and peaking facilities using existing technologies because of lower total capital costs.

Several commenters address the issue of technology choice and new technologies. CIPCA believes that adoption of the NOPRs will increase supply options but they do not cite a reason for their predicted impact (CIPCA, P. 3). In a similar vein, CFA&EA indicate that since smaller plants using new technologies have become considerably more efficient and competitive with larger plants (evidence in academic and policy literature cited in IPP NOPR) there is greater opportunity for this generation unde the new guidelines.

NIEP, however, believes that new renewable and cogeneration projects will be discouraged because IPPs and competitive bidding could reduce QF prices(NIEP, P. 8 & P. 14). Throughout its comments, NIEP claims that the government is shifting emphasis away from energy efficiency toward least-cost supply options only. By this, NIEP implies that more energy efficient technologies are not the least-cost solutions and that this competition will eliminate from consideration there more energy efficient technologies.

A third perspective is that of APPA. APPA believes that NOPRs are not needed and no new technology breakthroughs will occur as a result of the proposed rules. In addition, APPA states that IPPs are already being integrated into the current mix of generators and that breakthroughs in technology only wioll occur because of refinements of current machines (APPA, P. 1).

EEI also believes that the technology choice will be less than optimal due to regulatory bias, and the fact that technology choice may be overshadowed by the price. According to EEI, it may be difficult to select an appropriate combination of price and non-price factors in a bidding concept.

It is the consensus that the process of bidding may produce the least cost plant, but the impacts are unclear. Some argue that the bidding will rule out new, possible more capital intensive technologies, but others argue that it will promote more efficient technologies.

IMPACT ON FUEL MIX

The NOPR states that a benefit of the proposed rule changes may be the demonstration of a broader range of fossil fuel technologies which have higher efficiency and that producers who have IPP status may be more prone to implement these technologies than QFs and fully regulated jurisdictional utilities (IPP NOPR, P. 56-57). Commissioner Trabandt states that "the probable result (of the IPP NOPR) would favor natural gas and oil fired generation in the near term, with possibly some coal fired

p.34). Commissioner Trabandt considers this a problem, while the

Commission considers it a benefit: the proposals "may help foster development of certain high-efficiency technologies that use fossil fuels" including combined-cycle natural gas turbines and fluidized bed coal boilers.

The two commenters who mention fuel use, imply that it is a concern, especially regarding the possibility of using natural gas (APPA and NERC). NERC asserts that the displacement of solid fuels in the near term is contrary to the Fuel Use Act. NERC takes the position that non-utility generators will continue to increasingly depend on natural gas (they use as evidence the proponderence of gas generators), and that heavy reliance on gas affects long-term reliability.

It is clear that all parties expect that natural gas will increase as a result of the NOPRs. The question remains as to whether this increasing use of gas is a benefit or a concern for energy use in the nation's economy.

REALLOCATION OF RISKS

According to FERC, an IPP would assume most of the risks associated with construction and operations because utilities would only have to purchase IPP power on a voluntary basis (IPP NOPR, P. 58-59).. This shift of the risks from the utilities and customers to the IPP investors is necessary for economic efficiency "because decisions are then made by the same individuals who bear the risk of their decisions". Customers may continue to bear some of the same risks associated with demand forecasting and capacity decisions. However,.the ratepayers are not expected to bear any more risks than they do under current regulations. (IPP NOPR, P. 60).

Commissioner Trabandt agrees that the shift of risk to some extent will occur under this process, however he disagrees that the shift is a benefit. The extent of the risk, he claims is not clear, and more study is needed. He does state evidence (p. 39) that many of the projects may be unable to obtain financing since investors may not be willing to take the risks. Again however, the evidence on both sides is not overwhelming and as Commassioner Trabandt states "a systematic and objective analysis of this risk is clearly warranted..."

DISTORTION OF INVESTMENT

According to FERC, the new rules for IPPs would promote more rational investment decisions. Currently, some generation developers build "PURPA machines" which are plants with a contrived thermal application to avoid public utility regulation (IPP NOPR, P. 61-62). The new proposals would eliminate these uneconomic investments.

"CONCERNS" OUTLINED IN THE NOPRS

The NOPR indicates a number of "concerns" that have been raised about the proposals. These include a number of issues, and are the ones that are addressed the most in the dissenting comments. These include:

* Reliability
* Power Pooling

RELIABILITY

The issue of reliability is by far the most controversial. It is the concern that is raised the greatest number of times, and there are arguments to support both sides of the issue. FERC cites three reasons why reliability will not necessarily be affected by the integration of IPPs into the system. First, purchases from IPPs will still be voluntary, and if the utility wishes to purchase energy or capacity from the IPP, the utility would be free to negotiate terms that ensure reliability.

Second, in comparison to QF's, the IPPs do not necessarily have to support both electricity production and thermal energy production,. For many QF's the primary output is thermal power, and if those requirements dropped there would be concern that electricity supply might be decreased. This would not be a concern with the IPPs whose major function would be electricity generation.

Third, IPPs would have incentive to help utilities meet their obligation-to-serve. The IPPs have a contractural obligation to provide adequate service, and if they fail, they may not be paid, or the utility may take the plant over. This, according to FERC, is a good motivating force for supplying reliable power (IPP NOPR, P. 72-74).

On the other hand, Commissioner Trabandt argues that the impact on reliability would be great and negative. The arguments stem from the technical problems of interconnection and planning. Lack of information and cooperation may lead to problems in supply. His concern is with IPP defaults, finding that 'remedial' measures outlined are inadequate and place too much emphasis on legal and monetary solutions to problems that are really technical in nature (dissenting opinion p. 37-8). Trabandt also predicts that the NOPRs would result in increased reserve margins because more backup power would be required (Dissenting opinion, p. 65).

The commenters discussed this issue in a number of areas including: overall system reliability; system reserve margins; and IPP reliability. EEI, 40 Utilities, NERC, and PSCOM, feel that overall system reliability will be diminished with the adoption of the NOPRs (EEI, P. 25, 40 UTIL, P. 85, NERC, P. & PSCOM, P. 6). EEI states numerous reasons for overall system reliability being diminished. One of the reasons EEI cites is that non-utility generators may have fewer back-up or duplicate systems which decrease the probability of a total plant failure if one system fails. Another reason EEI gives is that bidding systems cannot or will not be designed to properly promote reliability requirements. As a result, the IPPs may not be the most reliable plants available and therefore will have a diminishing effect on overall system reliability. The issue of IPP reliaiblity is addressed below (EEI, Bidding Comment, Appendix B, P. 1).

NERC states that it is uncertain what number of non-utility generators could be integrated into the system without affecting overall system reliability (NERC, P. 13), though NERC believes the non-utility generators can jeopardize reliability. By this NERC implies that the individual generators will not be as reliable as existing generation. NERC also notes that non-utility generators may not have the same motivations and obligations as utilities and stresses that for there to be limited impacts on reliability the IPPs must meet the same requirements for reliability that utilities meet (NERC, 'A, P. 7).

Public Service Comission of Maryland (PSCOM) concurs that the flexible IPP regulations will not protect overall system reliability because the incentives do not exist for the non-utilities with regard to obligation-to-serve (PSCOM, P. 6).

On the other hand, CFA & EA feel that overall system reliability will be improved by the adoption of the NOPRs (CFA & EA, P. 8 & P. 12). This conclusion stems from a number of reasons including the use of probability theory which shows that reliability is increased as smaller plants are added to the system. CFA&EA further note that given the unreliability of large central station nuclear plants it is ironic that utilities are concerned with the reliability of smaller plants. Also, given take-over and penalty clauses that have been proposed in contracts, there should be little concern over reliable supplies.

Comments from APPA, EEI, and 40 Utilities predict that higher system reserve margins are necessary if the NOPRs are adopted (APPA, P. 4, 40 UTIL, P. 9, & EEI, Bidding Comments, Appendix B, P. 2, P. 8 & P. 13). APPA believes that there would be a significant number of new plants if cost-of-service rates are removed (APPA, P. 4) and therefore to keep existing levels of reliability, utilities will need higher reserve margins. This however is based on previous assumptions that IPP generation will be less reliabile than utility generation. EEI believes higher reserve margins will be needed because of the uncertainty due to increased competition (EEI, Bidding NOPR, Appendix B, P. 2, 8, and 13). 40 Utilities also believes the adoption of the NOPRs will result in uncertainty in planning and operations (40 UTIL, P. 9).

NERC, however, does point out that while smaller plants would theoretically require lower system reserve margins, that unit commitment schedules must be coordinated with the utility to ensure adequate reserve (NERC, 'R, P. 16). NERC does qualify these statements with saying that smaller units are generally more reliable than larger units, and if there are sets of guidelines for operation and interconnection of non-utility generators some of these problems can be solved.

Many of these arguments depend on whether the commenters view IPPs as being reliable and whether they can perform as reliably as utility operated plants. CIPCA states that IPPs can produce reliable power supplies and this has been shown by existing independent power producers and QF's (CIPCA, P.5).

INTEGRATION WITH POWER POOLS

FERC states that IPPs could be integrated into power pools. Purchases of IPP power by utilities would be on a voluntary basis. Thus, FERC states that utilities would not have to purchase IPP power unless the IPP met the power pools requirements. FERC cites an Institute of Electrical and Electronics Engineers representative who thinks that IPPs can be integrated into power pools (IPP NOPR, P. 76-77).

According to Trabandt, the impact of the NOPRs would be negative on regional power pooling arrangements due to the bidding and contractual structure set up by these rules. The reliability of these arrangements would be reduced (IPP NOPR, Appendix, P. 38). As for transmission requirements, Trabandt feels that the Commission needs to address this issue more throroughly (IPP NOPR, Appendix, P. 44-45).

EEI was the only commenter to address the impact of the NOPRs on power pool agreements. EEI predicts that power pool agreements could be adversely affected by adoption of the NOPRs. EEI feels that power pools agreements could be affected if parties are unwilling to share sensitive information. EEI also feels that administrative procedures and agreements will be hindered if the NOPRs are adopted (EEI, P. 28).

NERC believes that more contracts would be necessary to facilitate coordination between utility systems because of increased needs to specify back-up requirements, damages, and purchase rights among other factors (NERC, 'A, P. 17). 40 Utilities believe that cost associated with these contracts would be substantial. 40 Utilities does not cite a reason for the impact they predicted but they did cite Joskow & Schmalensee as evidence (40 UTIL, P. 74).

EEI predicts that actual inter-system coordination will be affected by adoption of the NOPRs. EEI believes the regulations may make it difficult to maintain proper frequency and voltage control (EEI, Bidding NOPR, Appendix B, P. 18-19).

Finally, each of the following commenters address the issue of transmission access in their documents: APPA, CFA & EA, CIPCA, NIEP, and EEI. CIPCA predicts that increased transmission capacity will be needed if the NOPRs are adopted and does not cite the reason they predict this impact (CIPCA, P. 28). The other three commenters stress the need for open access to transmission facilities as a key issue in the implementation of the NOPRs (APPA, P. 3, CFA & EA, P. 8, NIEP, P. 30-32, & (EEI, P. 28). APPA believes that electricity might be oversupplied at lower prices and will put a strain on transmission access (APPA, P. 3 and Appendix P. 1-2). CFA & EA find open access to transmission facilities to be essential if operating efficiency is to be achieved (CFA & EA, P. 8). NIEP believes open access is required in order for competition to take place (NIEP, P. 30-32). EEI is uncertain about the impact of the adoption of the NOPRs. EEI suggests that FERC examine the impact to scale economies for the transmission facilities needed to serve additional capacity (EEI, P. 28).

CONCLUSIONS

There are a number of issues that have been addressed in these comments that are key to the development of the proposals put forward by FERC. The major one is the rationale for the new rulings, and the disagreements about those reasons. It is the commissions assertion that there are impending problems in the electric utility industry, primarily concerned with new sources of supply. Based on recent history, the commission sees problems in future supply due to lack of investment by utilities. This lack of investment is caused by a number of factors, the primary factor being the risk aversion in the industry. This may, according to the commission, lead to capacity shortfalls and unreliable supplies of electricity in the late 1990's.

On the other hand, the dissenting opinions, led by Commissioner Trabandt, feel that there is no impending crisis in electricity supply, and under current regulations, utilities and private investors, will build capacity in sufficient quantities to maintain the integrity of electricity supply. Both of these viewpoints can be justified using existing data, and the evidence presented on both sides are not overwhelming. This specific issue needs to be addressed in a comprehensive study which examines the behavior of investment by utilities and private companies, and the relationship between past occurances, economic growth, and investment in electric power capacity.

The second major concern is the sucess of these proposals in mitigating those perceived problems. Three issues stand out as the most important; if the rules are truly "voluntary" will they have much of an impact?, will the rules provide the least-cost power?, and will they impact reliability of electric supply?

The least-cost supply issue and its implications is the centerpoint of this review. Will the procedures produce the least-cost supply? Will the competition, force out technologies that are more expensive, but also more environmentally acceptable, or more acceptable in terms of national energy policy? These are not rigorously answered.

The most argued concern is that of reliability. Both sides present cases on past evidence, and future scenarios. With existing evidence it is clear that reliability has not been endangered under existing PURPA rules (with small penetration of non-utility generators). However, what will the impact be if large numbers of small IPPs enter a grid?

None of the arguments presented refer to analyses that specifically address the issues caused by these proposals. The evidence comes from studies evaluating similar issues, but not addressing the exact same conditions. A comprehensive study evaluating the major points introduced here, using existing information, and predictions on behavioral aspects of investors is needed to directly address the impacts of the new proposals on independent power production.